Electricity Costing and Pricing Study

Volume VII

Costing Methodology for Determining Marginal Costs

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ELECTRICITY COSTING AND PRICING STUDY

VOLUME VII
COSTING METHODOLOGY FOR DETERMINING MARGINAL COSTS

Ontario Hydro
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Table of Contents

Page No

INTRODUCTION TO VOLUME VII 1

PART 1: AN ANALYSIS OF THE TIME-DIFFERENTIATED MARGINAL COSTS OF ONTARIO HYDRO 2

National Economic Research Associates, Inc. 2

I. INTRODUCTION 3

II. SUMMARY OF RESULTS 6

III. SELECTION OF COSTING PERIODS 9

IV. CAPACITY-RELATED COSTS 11

- **A. Marginal Cost of Generating Capacity** 11
- **B. Marginal Transmission Investment** 12
- **C. Transmission O&M Expenses** 12
- **D. Computation of Annual Carrying Charge** 12
  1. The Engineer's Approach 15
  2. The Economists's Approach 15
- **E. Computation of Marginal Unit Demand-Related Costs** 19
- **F. Marginal Demand-Related Costs by Period** 23

V. MARGINAL ENERGY COSTS 28

APPENDIX 1: A Simplified Model of Time-of-Day/Seasonal Pricing 34

APPENDIX 2: The Assignment of Marginal Capacity Costs to Costing Periods Based on Loss of Load Probabilities: an Elaboration 42

APPENDIX 3: Marginal Costing Study Data Sources 43

APPENDIX 3A: Data Required by NERA 44

APPENDIX 4: Recommendations for Improving Data Inputs to the Marginal Costing Study 45
ADDENDUM TO NERA REPORT 46

PART 2: MARGINAL COSTS FOR THE DISTRIBUTION SYSTEM 49

I. INTRODUCTION 49

II. SCOPE 50

III. TRANSFORMATION 51

A. Capital 51
B. Operation and Maintenance 51
C. Transformation Losses 51

IV. DISTRIBUTION 52

A. Capital 52
B. Operation and Maintenance 52

V. METERS 53

A. Capital 53
B. Operation and Maintenance 53

VI. ANNUALIZATION AND ESCALATION OF INCREMENTAL COSTS 54

PART 3: MARGINAL COSTS FOR THE RURAL RETAIL SYSTEM 55

I. INTRODUCTION 55

II. CONCEPTUAL BASIS FOR ALLOCATING COSTS 56

III. ALLOCATING CAPITAL COSTS 57

IV. ESTABLISHING THE UNIT COSTS FOR CONDUCTORS AND TRANSFORMERS 58

V. FIXED AND VARIABLE COMPONENTS OF CONDUCTOR EXPENDITURES 59

VI. FIXED AND VARIABLE COMPONENTS OF TRANSFORMER EXPENDITURE 61

VII. FIXED AND VARIABLE COSTS OF INSTALLING TRANSFORMERS 62

VIII. RESULTS OF CAPITAL ALLOCATION 63

IX. ALLOCATING COSTS FOR OPERATION, MAINTENANCE, AND ADMINISTRATION 64

X. DETERMINING INCREMENTAL FIXED AND VARIABLE COSTS 65

XI. ANNUALIZING AND ESCALATING INCREMENTAL COSTS 66

APPENDIX I: Summary of Marginal Non-Common Costs in 1977, 1978 and 1979 Dollars 67

APPENDIX II: New Information Requirements for Electricity Costing Marginal Non-Common Function Costs 68

APPENDIX III: Summary of Incremental Fixed and Variable Costs for 1975 in the Rural Retail System in 1975 Dollars 71

APPENDIX IV: Summary of Incremental Fixed and Variable Costs in the Rural Retail System in 1975, 1977, 1978, and 1979 Dollars 72

APPENDIX V: Information Requirements for Electricity Costing: Marginal Costs in the Retail System 73

INTRODUCTION TO VOLUME VII

The determination of Ontario Hydro's marginal costs has been undertaken in three segments. These are as follows:

Part 1. The marginal costs of the bulk-power system;

Part 2. The marginal costs of the distribution system;

Part 3. The marginal costs of the rural retail system.

The study of the bulk-power system has been performed by National Economic Research Associates, Inc. (NERA), a consulting firm based in New York, with an international reputation in the field of utility economics.

The two remaining analyses were performed by Ontario Hydro personnel, to provide an indication of the end rates which would result from applying marginal-cost pricing. Although these studies may not be as sophisticated as the NERA paper, they do achieve the proposed purpose.

The methodologies used and the results of the three marginal-cost studies form the remainder of this volume.

PART 1: An Analysis of the Time-Differentiated Marginal Costs of Ontario Hydro

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC.

August 18, 1976

I. INTRODUCTION

The purpose of this report is to provide input, with regard to the time-differentiated marginal costs of providing electric utility service, to Ontario Hydro's examination of alternative costing and pricing methodologies.

Since it is our understanding that any implementation of a marginal costing system (if adopted) will take place in a future period, the computations contained herein should only be considered as illustrative of the methodology described in this report. The reason for this is that, during the course of the study, changes were made in forecasted loads and in planned capacity additions. Should Ontario Hydro implement a marginal costing system in a future time period, it will be necessary to reevaluate marginal costs.

Why should marginal costs be considered? The economist tells us that, if our goal is economic efficiency, the prices for all goods and services should be equal to their respective marginal costs, and that marginal costs can generally be defined as the costs of resources used to produce an additional unit of some commodity or the value of resources that would be saved by producing one less unit of that commodity. The economist reasons that at a point in time the economy has a fixed amount of productive resources and the critical economic problem is to employ these scarce resources in the most efficient manner. Given this fixed bundle of resources, the decision to produce more of any particular commodity also is a decision to produce less of one or more other commodities. In the Canadian economy, the choice of what should be produced and what should not be produced generally is left to the voluntary decisions of individual consumers. Consumers make these decisions based on their own preferences and incomes, and are guided in their decisions by the prices of the various commodities that they can choose from.

The demand for all commodities is to some extent responsive to price. If consumers are to make intelligent decisions regarding which commodities and how much of each to purchase, the prices that they face must reflect the resource cost of consuming one more or one less unit of the commodity; that is, prices should reflect marginal cost. When the prices observed by consumers reflect marginal cost, their consumption decisions will correctly reflect what it costs producing agents to provide more or less of each commodity. In this way the independent decisions of millions of consumers guide the economy's scarce resources into those sectors of production that yield greater satisfaction to consumers than all other alternatives. This means that total satisfaction will be maximized.

For example, if the price for some commodity like electricity is set below its marginal cost, consumers will think it is cheaper to purchase an additional unit than it really costs society to produce it. The consumer will then be led to expand his consumption to the point where the marginal value of an additional unit is set equal to its price. But since the price has been set below the marginal cost, the value of the last unit of consumption to the consumer is less than what it costs society to produce it. More resources are being devoted to the production of the commodity than is socially efficient.

How does this economic concept relate to what is "fair"? Marginal cost is not necessarily equal to historic average cost, and, from the consumers' viewpoint, it may be hard for them to understand why they are not being charged historic average cost. After all, everybody cannot be consuming the "marginal" unit of electricity. Are not some people consuming power that is produced at other than marginal cost? To the economist, the notion of marginal cost is the cost of producing one more unit of a good. The textbook example has the economist calculating marginal cost by taking the first derivative of the total cost curve for a quantity of output. This is the cost that will be faced if another unit is demanded and the cost that will be saved if a unit less is demanded. So, regardless of the average cost, a change in any consumer's decision to consume or not to consume will cost or save the producer the marginal cost. Fairness demands that the cost of somebody's decision be the price that he pays for that decision.

Referring to the textbook definition of marginal costs brings up an interesting question. The marginal cost is pegged to a given level of output. What would happen if this level changed? Is the computation so volatile as to be useless in setting rates which we expect to have some stability? What would happen if, for example, a large natural gas field was discovered immediately outside of Toronto and all of Ontario Hydro's space-conditioning consumers converted to natural gas, causing a large excess of electric production capacity sufficient to last through the end of this century? Obviously, the marginal cost of electric production would be quite different than it is currently. Increased demand would not require additional capacity and marginal cost would plummet below historic average costs. However, this is not the case and we cannot make rational plans based on unrealistic assumptions. As the province of Ontario grows, more energy is going to be needed. The demand for electricity will grow and whether it grows at 1, 3 or 7 per cent a year, more facilities will have to be provided. Within such a range, Ontario Hydro's circumstances could drastically change the marginal cost of electricity production within a very small period of time.

How does this concept of the economist relate to the costs of electricity? Since the demand for electricity is periodic and since its supply is essentially nonstorable, the costs of supplying additional consumption are variable. Normally, additional consumption taken at a time when capacity is fully, or almost fully, utilized requires that high energy cost peaking plants be run more extensively. Additionally, because of capacity limitations, there may be a shortage, in which case some demands for consumption cannot be met. In the longer term, when plant capacity is variable, a permanent increment of load during peak hours may require the addition of capacity.

During periods of time when demand is low relative to available capacity, additional consumption can be met from existing plant by running baseload plants (which have relatively low running costs) more intensively and without any chance of causing shortages. In the long run, a sustained increase in off-peak consumption, to the extent that it is small enough so as not to affect reserve requirements, might lead us to change the mix of plants that we have on line, to take advantage of the generation economies associated with a higher load factor, but not to increase the overall capacity of the system. Additional off-peak consumption in this case, even if sustained, does not result in additional capacity costs being imposed on the system. As a result, it generally is conceded that marginal costs during peak periods generally are considerably higher than during off-peak periods.

We can think of on-peak and off-peak electricity as different commodities having different costs. When two commodities with different costs of production are identically priced, there is a tendency for too little to be consumed of the overpriced product, while too much is consumed of the underpriced product.

In more explicit terms, air conditioning is a peak-period use for which (in general) average energy costs are charged even though the energy cost of supplying that use is greater than the average cost of energy; nighttime use also is being charged at the average cost of energy, even though the energy cost of supplying that use is less than the average cost of energy. Consumers have been receiving the wrong signals. They continue to demand increasing quantities of peak-period electricity for air conditioning because they are being charged less than the cost of providing that electricity. On some electric systems (in the United States), daily load factors have begun to deteriorate as average prices have risen. This is an indication that nighttime (off-peak) prices are too high and that the consumer is foregoing usage at that time. Thus, there is a common sense aspect to the economist's theoretical notion of marginal cost pricing that does apply to the electric utility industry. (In the case of this particular example of the time-related use of electricity, it may be that nighttime off-peak costs are sufficiently low so as to encourage the development of storage cooling.)

The marginal cost of supplying electric service can be separated into three categories. The first, marginal customer cost, is the cost associated with building and having in place an electric system that provides area coverage and "hook-up" for a population of minimum demand customers. In the case of Ontario Hydro's bulk power system, this cost in relation to the other costs is too minimal to measure. The second, marginal demand cost, is the cost associated with building and maintaining a system with sufficient capacity to meet incremental electrical demands. The third, marginal energy cost, is the cost of producing the power that is demanded. Each of these costs is computed in terms of current or "real" dollars and thus they do not reflect any general inflationary expectations. This is done in order that these costs might reflect today's costs of providing electric service. In this way, the consumers, in their decision-making processes, will be choosing between electricity and some other good or service on the basis of costs stated in current dollars.

What are the characteristics of these costs? Turning first to capacity- or demand-related costs, we find that they tend to be lumpy. Scale economies and construction lead times combined dictate the installation of large discrete lumps of capacity. These large lumps of capacity both relieve loads on older, less efficient units (in the case of generation), and allow room for additional growth on the system. Taking our lead from Boiteaux, [1] we have treated these lumpy additions as though they were more flexible and could be had in very small increments of capacity. To do so, we have derived unit costs of generation based on the unit cost of capacity. In the case of Ontario Hydro's transmission system, we have utilized the future stream of transmission investments related to load to derive a unit capacity cost. Both of these unit costs are expressed in current dollars, and they represent today's cost of adding a small increment of load to Ontario Hydro's system.

With respect to marginal energy costs, it is also necessary to examine costs over a period of years. The appropriate measure of marginal energy costs is an average of marginal costs over the period examined. The reason is that system optimality cannot be thought of as a point occurrence as long as there is growth. Here, again, it is the combination of scale economies and construction lead times that makes it necessary to get at the appropriate measure of marginal cost in a somewhat roundabout manner. Let us look at a simple example to illustrate the point. In a thermally dominated generation system, peaking units will be added first, followed by a baseload unit. During the construction of the baseload plant, the peaking units will be required to run a longer number of hours than indicated as being optimal by the economic trade-offs between these two types of plant. When the baseload unit comes on line, the peaking units will run less than the optimal number of hours. Over the period of a planning cycle, the peaking unit will, on average, operate the optimal number of hours.

The long-run marginal demand and energy costs of an electric utility vary with the time of consumption. The marginal cost of energy at a given time is the marginal fuel and variable operation and maintenance expense that will result from an increment in demand at that time. In other words, for each hour of the year the plants available for use are arranged in ascending order of operating costs; the generation plan is usually to add operating units in ascending order of running costs as demand increases; and, therefore, the marginal cost curve for each hour is the relationship between kilowatt-hour demand and the running costs per kilowatt-hour.

This marginal cost curve can be thought of as rising, with running costs, until the point at which capacity is exceeded, where the cost becomes the shortage cost and the curve rises very sharply. The shortage cost corresponds to the costs incurred by customers who would not be served in the event of demand exceeding capacity. These costs could, in principle, be calculated directly. The French nationalized electricity industry does just that; it looks at its plan for load shedding and calculates the loss of value added for industries which it would shed in a situation of potential power failure. It then plans to add capacity to the point at which the cost of the last unit of capacity added equals the probable cost of a failure. Ontario Hydro, however, sets its capacity requirements (including reserves) with reference to a set of reliability criteria. We assume that, while set subjectively, these criteria adequately reflect the shortage costs or the costs of not having enough. This means that the system has been planned to equalize the cost of failure with the last unit of capacity; the shortage costs can then be determined, as it were, in reverse, by reference to the capital cost of the last unit of capacity. This "last unit" of capacity is the unit which the company customarily would use to meet the peak or the lowest cost unit available to it. We can think of the shortage cost as equal to the rental cost of capacity, which may be the annual capital per-kilowatt charges on a gas turbine; but in some cases it will be the manning and maintenance costs of an old unit. This will also be true for a utility adding baseload capacity. The reason is that the decision to add a kilowatt of baseload capacity is made after consideration of the fuel savings which can be made throughout the system. When a system is optimally adjusted to the load, the fuel savings attributable to a baseload plant will just equal the excess of baseload capital costs over those of the cheapest available plant economically suitable for that system.

This shortage cost, or marginal capacity cost, cannot simply be charged to the peak hour. Rather, the cost must be assigned, in principle, to each hour based on the probability that load will exceed capacity in that hour. We say this because the reliability criterion commonly used is the sum of the probabilities for each

[1]Marcel Boiteux and Paul Stasi, "The Determination of Costs of Expansion of an Interconnected System of Production and Distribution of Electricity," *Marginal Cost Pricing in Practice*, J. Nelson, ed. (Englewood Cliffs, New Jersey: Prentice-Hall, Inc., 1964).

hour that the load will not be met. Simply put, during some hours there is a greater risk that capacity will be exceeded than in others. Thus, it is logical, in principle, to assign a proportion of the responsibility for the cost of the ''last unit'' of capacity to each hour in proportion to the degree of risk that capacity will be exceeded. As will be seen later in this report, it is not necessary as a practical matter to make this computation for every hour of the year.

It is important to recognize that these marginal costs *do not* represent a form of prospective rate base or average incremental costs, but reflect the time-differentiated marginal costs upon which consumption decisions should be based. These costs do represent the cost of reproducing the service provided at today's costs and under today's technologies, and are the costs that, in the long run (as defined by the economist, not the temporal long run), will be saved or incurred in the production and delivery of electric energy. Many people have incorrectly come to view marginal cost as the cost of growth. Economically speaking, this view is wrong because in the long run it will be necessary, even without peak-load growth, to replace old and unreliable facilities at current costs. Thus, in the long run, a decision to consume less electricity will reduce the costs incurred in that replacement.

II. SUMMARY OF RESULTS

Before setting forth the numerical results of our analysis, we feel it necessary to give voice to two qualifying comments as to the interpretation and use of those numerical results.

In the traditional, nontime-differentiated approach to costing for ratemaking purposes, there is a very clear separation between costing and ratemaking. Theoretically speaking, it is possible to maintain the same very clear separation between these two elements when computing time-differentiated marginal costs. Pragmatically, however, it makes little sense to compute a cost for each hour of the year when one clearly would not attempt to price every hour of the year. Therefore, we have computed marginal costs for groups of hours into which it makes both economic and ratemaking sense to divide the hours of the day, days of the week and seasons of the year. Based on our analysis, as well as on discussion with Ontario Hydro personnel, all weekday hours between 0700 hours and 2300 hours have been designated as peak-period hours, with a distinction being made between summer peak-period hours and winter peak-period hours. All other weekday hours, plus total weekend hours, have been designated as off-peak periods with no seasonal distinction. Should it become desirable to define the peak period more narrowly, some of the cost components must be recomputed.

In the summary table which follows, we present our estimates of the marginal costs for each of the time periods delineated above based on the familiar engineering economics concepts of levelized annual charges.

	Based On Levelized Annual Charge	
	Marginal Capacity Cost (Dollars per Kw of Seasonal Peak Demand)	Marginal Energy Cost (Cents per Kw)
	(1)	(2)
Peak Hours		
Winter	$38.06	1.7¢
Summer	$ 6.34	1.5¢
Off-Peak Hours		
Annual	-	1.2¢

We wish to point out that while this familiar concept does simulate the regulatory concept, it does not necessarily simulate the carrying charge that would arise in a competitive marketplace. The economist's concern in computing marginal costs for electric utility service is that when consumers are faced with choices between electricity con- sumption and competing goods and services, they should make their decisions faced with costs having the same economic basis. To this end, the economist would devise a set of carrying charges that simulates those carrying charges that would arise in the competitive marketplace. *We believe that the approach advocated by the economist produces the best estimate of Ontario Hydro's time-differentiated marginal costs and is the one that should be utilized for ratemaking purposes.* (A discussion of the economist's approach can be found in the body of this report.)

A description of the rationale for and the choice of costing periods, and a description of the methodology used to derive the various components of marginal cost follow. The appended schedules show, in greater detail, the computations behind these costs.

In view of the recent spate of articles in the US trade press, as well as the speeches and comments of a number of economists addressing (usually) that which NERA was doing some time ago, a word is in order as to how the NERA methodology has evolved over the past five years or so.

In the late 1960s with technological progress still reducing generating costs, with economies of scale still indisputably present and with inflation at a very low rate, average costs of electricity were considerably higher than marginal costs. This was particularly true with respect to off-peak usage. There was, therefore, clear justification for pricing such usage at less than average costs; but commissions were reluctant to approve such rates lest they be exposed to the charge of fostering discriminatory practices. It was to allay this concern that certain utility companies sought to present the economic cost justification for these load-factor improving rates, relying on the very same costing theory we advance here, i.e., that marginal cost is the proper test as the rates' propriety. It was in these early proceedings that the first versions of long-run incremental costs, soon dubbed LRIC, were introduced. This was defined as:

> *All costs associated with the addition of a given quantum of service... The concept refers to the long run; any costs which may be added as a result of adding or expanding a service, including those costs which will not immediately be incurred, are included in the total incremental cost of a service offering. In other words, these (total incremental) costs are long run in the sense that they include the addition to total costs when the company has fully adjusted its operations and facilities to the most efficient means of meeting the increased total demand.*

At that time electric sales were growing rapidly and the prime consideration was the cost of taking on new load. Costs were computed in the form of annual kilowatt charges for meeting the new demand at the time of the system peak, the compatible energy costs and the related customer costs. No attempt was made to allocate these annual costs between the different periods of the year, though rudimentary support for summer/winter differentials was developed.

This methodology developed from rate case to rate case as computation improvements suggested themselves. For instance, it was recognized that nuclear plants with their much higher first costs were being introduced to affect *energy cost* savings as well as to meet new load requirements, and allowances were made for this effect. Refinements were introduced as to the methodology for separating distribution costs which vary with demand from those costs which were strictly related to customer coverage. Developments such as these culminated in the cost presentation in 1973, before the Wisconsin Public Service Commission in the Madison Gas and Electric case of that year.

That particular period of late 1973/early 1974 marked a turning point in the energy world, with the combination of a three-to-four fold increase in energy costs and 1974's very severe

inflation causing capacity (and energy) costs to surge to new heights. The need for rate relief became urgent; but customer resistance noncomitantly reached a new high. Environmental groups reacted to the circumstances and were actively interested in the ratemaking process. ''Time-of-day,'' ''peak-load'' pricing was prescribed as the solution, purportedly to moderate the increased need for generating capacity and to curb the alleged wasteful use of electricity.

To respond to this challenge, many utility companies engaged in the study of the proper costing techniques needed to support time-of-usage pricing. It is as a result of this area of study that the methodology used in this report was evolved. It has been offered in a number of jurisdictions, in the years 1975-1976, as the appropriate standard for marginal cost ratemaking.

In terms of overall annual costs, the two methods (LRIC and time-differentiated marginal costs) produced generally the same results, but the individual cost components do vary. Thus, the advanced methodology more systematically applies a part of the capacity cost to the load being served outside of the normal peak months, though this was always recognized as necessary to some degree. Also, a more systematic method was developed for including in the energy cost element the recognition that a substantial part of the capital cost is incurred for the purpose of saving energy cost and not merely to meet peak loads. The general effect of these changes has been (paradoxically) to place a somewhat lower emphasis on the demand (capacity) cost element, and on the costs at the particular time of the system peak, correspondingly somewhat greater emphasis on the energy cost element, and on service during the off-peak months. A comparison of the methodologies is summarized in the following table:

These costing methods have been evolving for some eight years now. It is not claimed that the final improvements have been made, since people are always trying to find a better way to ''skin the cat.'' We are satisfied, however, that the methodology we are using is soundly conceived, well-tested under real-world conditions, and now an appropriate one to assign the marginal costs of providing service to the different seasons of the year and times of day.

A QUICK GUIDE TO LRIC AND TIME-DIFFERENTIATED MARGINAL COSTING

Costing	LRIC	Time-Differentiated Marginal Costs
Capital cost of generation	Mean expected plant cost per Kw over planning horizon. Current dollars.	Least capital intensive plant used on system, usually a peaker. Current dollars.
Annualization (Carrying charges)	Levelized at current rates of interest, including taxes.	Annual charge reduced by (approximately) rate of inflation, includes taxes.
Fuel costs	Average fuel cost. Current prices.	Marginal fuel cost (always > average). Current prices.
Distribution and transmission	Mean per-Kw cost of recently installed capacity.	
Customer costs	(Judgmental)	Minimal system
Capacity responsibility	Some measure of peak responsibility	Loss-of-load probability

III. SELECTION OF COSTING PERIODS

When we examine the way in which most electric utility systems plan for the generation of electricity, it is evident that it is not only the one peak hour that is responsible for capacity additions; the need for capacity depends on the probable available capacity and the probable demand in each hour. Formal computations of the probability that load will exceed capacity are generally referred to as the loss-of-load probabilities (LOLP). The LOLPs so calculated are summed and compared to the system reliability criterion. This criterion represents the acceptable level of risk of failure to supply the load demanded.

In the light of this planning criterion, we will consider peak responsibility to be a graduated responsibility and assign the marginal cost of capacity (in principle) to each hour in proportion to its LOLP. (The rationale for the use of the LOLP measure in assigning marginal capacity costs to the costing periods is discussed in Appendix 2.) Thus, carried to the extreme, as a purely theoretical matter, each of the 8,760 hours in a year could be costed separately and could be considered to be a pricing period. Clearly, this would be administratively impractical and also incomprehensible to the vast majority of consumers to whom price signals should be given. Pragmatically, hours of similar costs should be grouped in a manner that makes sense and is easily understood by consumers.

While it is of paramount importance that the consumer be informed of the cost of the decision to consume at any given time (hence the move towards time-differentiated marginal cost pricing), a balance must be struck between a precise delineation of time-differentiated costs that would leave the consumer totally bewildered and a gross averaging of marginal cost prices over time that would defeat the purpose of using marginal cost price signals. In other words, one faces a cost-benefit trade-off between consumer confusion and economic efficiency.

In the course of evaluating this trade-off, consideration must also be given to the fact that very little is known about peak-period price elasticities. If such elasticities were known, one could predict shifts in the patterns of electricity consumption and compute the time-differentiated marginal costs associated with the new patterns of use. This is an iterative process that seeks an equilibrium between the cost a consumer is willing to pay to consume at any time and the cost of supplying electricity at that time.

However, since measurements of peak-period elasticities are not currently available, the iterative process described above cannot at this time be performed. We, therefore, have taken a "cold feet" approach and have defined the diurnal peak period in a relatively broad manner in order to avoid the risk of "peak-chasing" [1] until more is known about peak-period elasticities. In this way, movement towards the use of marginal costs as rates can begin without precise knowledge of peak-period elasticities and with a very low probability that any first steps will have to be reversed.

Ontario Hydro supplied loss-of-load probabilities by month for the period 1976-1985. Schedule III-1 shows for each month of this period the average loss-of-load probability. As the LOLP calculation is very sensitive to factors such as the maintenance schedule, which can be accurately predicted on a seasonal or annual basis but is extremely difficult to pinpoint on a monthly basis, it is necessary to combine months of similar LOLP values into seasons in a fashion that comports with monthly load patterns and traditional factors such as the demand for electric heat or space conditioning. The LOLPs computed by Ontario Hydro led us to conclude that there were two appropriate costing seasons, winter (October-March) and summer (April-September). The LOLPs did not justify the selection of more than two seasons.

Seasonal differences are, however, only one aspect of time-differentiated costs. It is generally accepted that as load falls linearly, LOLP decreases roughly exponentially. The risk that a system that is able to meet its daily peak will have a capacity shortfall at night when load falls below 85 per cent of daily peak is minimal. Calculations done at NERA's request show that nighttime LOLPs are about 1/10 to 1/100 that of daytime LOLPs. On the basis of cost differentials from demand at day and night, we have concluded that night or off-peak hours should constitute a separate costing period and that no capacity costs should be assigned to these hours.

A statistical analysis of Ontario Hydro's daily load patterns during each of the seasonal periods chosen indicated the existence of a broad plateau between the hours 0700 and 2300. [2] During the winter season there is a three-to-four-hour period when loads are some 10 per cent above this plateau and during the summer season loads are fairly flat.

We concluded that a peak period beginning at 0700 hours and ending at 2300 hours would meet the criterion of grouping hours of similar cost together and yet be broad enough not to create a substantial risk of creating a new peak and changing the costing picture. Loads during these hours are sufficiently high in comparison to daily peak loads that choosing a narrower period as the peak could result in the creation of a higher peak and a disruption of operating conditions on the electric system.

In addition, these hours are considered peak hours by Ontario Hydro operating personnel, and as a general matter the peaking hydraulic production facilities and more expensive thermal production facilities are operated only during these hours. Thus, the daily costing period selected groups hours of similar cost together for both marginal energy and marginal demand costs.

[1] "Peak-chasing" can occur if the cost of consumption during a narrowly defined peak period is very much higher than the cost of consumption during the immediately adjacent time period. The reason is that it is relatively easier to shift a particular consumption by, say, one hour than it is to shift that consumption by six hours.

[2] Technically, the summer plateau could be said to end at 2200 hours. However, it was felt that a uniform daily peak-time period was more desirable for ratemaking purposes.

ONTARIO HYDRO
CALCULATION OF RELATIVE MEAN VALUE OF LOSS-OF-LOAD PROBABILITIES BY COSTING PERIOD

Costing Period	LOLP[1]	Mean LOLP in Period	Mean LOLP ÷ Σ Mean LOLP	Relative Value of LOLP
	--(Days per	Year)---		
	(1)	(2)	(3)	(4)
Winter				
October	1.401			
November	3.690			
December	3.382			
January	0.849			
February	2.487			
March	1.176			
	12.985	2.164	0.872	0.87
Base Running				
April	0.459			
May	0.113			
June	0.338			
July	0.227			
August	0.274			
September	0.503			
	1.914	0.319	0.128	0.13

[1]Ten-year (1976-1985) average of Ontario Hydro loss-of-load probabilities.

Source: Based on data supplied by Ontario Hydro.

IV. CAPACITY-RELATED COSTS

A. MARGINAL COST OF GENERATING CAPACITY

An electric utility must construct sufficient generating capacity to meet its peak demand. Traditionally, the capital cost of this generating capacity, which includes a mix of baseload, intermediate and peaking plants, has been considered a fixed cost causally related to system peak demand. Yet, it is clear that the system is not constructed to serve only the peak. In fact, the generation mix and the resulting capital costs of a system constructed to serve only the peak would be quite different from a system constructed to serve load patterns that utilities commonly face.

The determination of the marginal cost of generating capacity requires an understanding of the planning process. Simply put, the planner attempts to meet the loads depicted by the load duration curve by choosing, from all plans capable of supplying the anticipated loads, the least possible cost plan. The least possible cost plan is the plan that yields the lowest present worth of all costs to be incurred over the life of the equipment to be used in carrying out the plan. To accomplish this, the planner must pick and choose from an array of possible plants which vary in initial cost, expected life and running costs per kilowatt-hour.

How does the planner choose the best plan? He does so by means of a series of economic trade-offs between the operating and capital cost characteristics of the available kinds of capacity and the requirements of the load duration curve.

For each possible plant, there is a series of total costs per kilowatt which rises according to the number of hours the plant is used. As the number of hours of use increases, there comes a point at which additional operation of this machine will result in a higher total cost than if some other machine were to be used. Let us consider that there are three kinds of equipment available:

1. Peaking units having low capital costs and high running costs;
2. Cycling units having medium capital costs and medium running costs; and
3. Baseload units having high capital costs and low running costs.

The planner attempts to "fill" the area under the load duration curve in the following notional way in order to minimize total cost:

1. Select an amount of baseload capacity such that the minimum number of hours any unit of baseload capacity runs is the number of hours at which the total cost of a unit of baseload capacity is less than or equal to that of a cycling unit.
2. Use an amount of cycling capacity defined in a similar manner.
3. Fill the remaining area with peaking units. Additionally, if the planner was asked how he would meet an additional increment of load at the peak, his answer would always be to use a peaking unit (or some equivalent low capital cost alternative).

This is clearly inconsistent with the more traditional view that the cost of capacity at the peak is the average cost of all capacity required to meet the peak. However, there is pragmatic evidence that this view is wrong. The British CEGB found that when it charged average capacity costs at peak, its Area Boards found it economical to put in peaking capacity at a much lower capital cost. Recently, the same issue has arisen in North Carolina. Municipal systems are proposing to purchase combustion turbines to avoid per-kilowatt charges developed by "averaging in" the much higher costs of baseload plants. Clearly, average capacity costs are higher than the real cost of meeting the peak.

It is necessary to determine the time-differentiated marginal costs that increments in demand actually impose upon the system. This can best be accomplished by turning to the load duration curve and asking what increase in costs would result from an increment in demand at any time. Clearly, in the short run, before capacity can be adjusted, the marginal cost is the cost of energy for the hours served plus the shortage cost (see Section III) for the hours not served. In the long run, after capacity has been adjusted, the marginal cost is the cost of energy plus the cost of capacity at peak. In an optimal system, the long-run costs equal the short-run costs; in fact, the following are all equal on an annual basis:

1. The cost of a peaker;
2. The long-run marginal cost of system peak demand; and
3. The short-run marginal cost of system peak demand (shortage cost).

In any real system, there are likely to be temporary mismatches, if only because of the discontinuous nature of plant adjustment. After a new plant addition, the short-run costs will probably be lower than the long-run costs: the running costs will be lower because of the new efficient capacity, and the probability of outage (and hence probable shortage costs) will be low. As the demand grows, the costs approach and exceed their long-run level, triggering more capacity additions. Rather than follow the short-run costs in their oscillations around an equilibrium level, for tariff-making purposes we can imagine a plant continuously adapted to demand in which the long-run marginal cost of capacity is also the appropriate short-run cost of curtailment.

In general, the marginal cost of capacity will be the cost of a peaking plant. Exceptions will occur in cases where the load characteristics are such that peaking plant would never be used to meet the peak, even in long-run equilibrium, as, for example, in a company with a high annual load factor. In this case, the plant with the next lowest capital cost should be used as the marginal cost of capacity. Running costs at the peak will be commensurately lower. Also, the cost will be charged over a larger number of hours since the high load factor will cause many more hours to have a significant LOLP. A utility with a very high load factor may therefore show little variation in hourly costs.

Problems arise with this approach only if there is a chronic imbalance in the system. In cases of permanent overcapacity, the correct approach is to adopt the short-run costs of providing service, in order to make the best possible use of existing capacity without burdening current users with capital costs of equipment they neither want nor need.

An examination of Ontario Hydro's annual load duration curve vis-a-vis the costs of plants presently available to the planner shows that combustion turbines would be the least cost method of meeting the top 15 to 20 per cent of the load. The flexibility attained by Ontario Hydro's hydraulic production facilities has put off (temporally) the need for combustion turbines. Yet, prospectively, Ontario Hydro generation additions are all thermal. Increments in expected demand that are of short duration and cause the planner to add generating capacity would be met by the use of a combustion turbine. From an economic point of

view, the marginal cost of an increment in demand for Ontario Hydro is the capital cost of a combustion turbine. In 1975 dollars, this cost based on data supplied by Ontario Hydro is $155 per kilowatt. For use in the marginal cost study, we have adjusted this figure to $186 per kilowatt to account for a reserve margin of 20 per cent, which is the lowest practical reserve that we understand Ontario Hydro would wish to maintain.

B. MARGINAL TRANSMISSION INVESTMENT

The analysis of marginal transmission investment seeks to express the unit marginal cost in transmission facilities resulting from an increment or decrement in load. To this end, we ask: What are the causative factors of investment in transmission facilities? What system characteristics are responsible for an increase or decrease in the amount of transmission investment?

The chief aim of the transmission planner is to ensure that an adequate amount of power can be delivered to all points on the system at all times. To this end, the planner designs a system capable of serving the worst possible case, that is, transporting the peak load under outage conditions.

Thus, the capacity of the transmission network is determined by the peak load on the system and outage contingency employed in evaluating transmission system reliability. Assuming that the cost of reliability properly reflects a trade-off with the cost of outage and will remain constant relative to total transmission investment, the capacity of the transmission network will vary with the expected size of the peak demand. The proper marginal unit cost for transmission investment, therefore, is a cost per kilowatt of system peak demand.

High voltage transmission facilities consist of large expensive components. A utility does not build transmission facilities to a specified peak level and then add small additions as load grows to enlarge the system's capability. Instead, the planner, working from a set of forecast peak loads, will design the system that will, over time, yield the least total cost. The planner accomplishes this by choosing the number of corridors, the size of corridors and the transmission voltage level that most economically transports the loads he expects to face. As voltage levels increase, the costs of corridors, towers and conductors all rise. With certain load densities, economies of scale may result from higher voltage transmission. The marginal cost per kilowatt of transmission investment is, therefore, not necessarily a linear function.

We can see from the foregoing that, as stated earlier in this report, transmission investment tends to be lumpy. In order to treat these lumpy additions as though they were more flexible and could be had in very small increments, it is necessary to look at them over time in order to develop the marginal unit costs of capacity. The unit marginal cost we seek may be thought of as the unit cost of putting in place - all at once - the transmission capacity necessary to serve the aggregate system peak. Thus, in what follows, we are *not* attempting to cost growth.

The methodology used to derive the marginal cost of investment in transmission facilities is to ask the planner, given a peak-load forecast, how he would design the transmission network. The investment from this plan would take into account the different capacities and costs of transmission at various voltage levels. The unit marginal cost level is then determined by dividing incremental investment by additions to peak demand.

To ensure that the resulting cost represents the long-run level of marginal transmission investment, it is necessary to determine whether the additions to transmission plant during a period properly reflect the load added during that period. It is possible that transmission plant is being built for future loads or that plant built in the past was designed to serve incremental loads. In either of these cases, it is necessary to align correctly additions to transmission plant with additions to peak load.

Initially, transmission investment for Ontario Hydro was analyzed for retrospective and prospective periods. However, due to problems with plant account data, which leave large investments in an interim capital account instead of clearing them to functional subaccounts, and the lack of an accurate construction cost index to convert past investment to today's dollars, only the prospective period has been used to determine the long-run level of marginal transmission investment. Schedule IV-B-1 shows this computation. Ontario Hydro's budgeted transmission figures for 1975-1980 were converted to 1975 dollars and divided by additions to system peak for 1975-1980 to arrive at a marginal cost of investment in transmission facilities of $168 per kilowatt of system peak demand. Ontario Hydro personnel have indicated that expenditures during this period properly reflect facilities which will serve load added during the period.

It should be noted here that we would have preferred to be able to analyze transmission investment both retrospectively and prospectively so as to be able to derive mathematically a function expressing the relationship between transmission plant investments and demands. We are confident that our inability to do so, however, does not constitute a fatal flaw in the analysis. We say this because it is our understanding that, during the period studied, the Hydro's planned additions to transmission plant will follow the same patterns as those of the recent path and therefore represent an extension of any mathematical function that might have been derived had the data been available.

C. TRANSMISSION O&M EXPENSES

Transmission O&M expenses are related to the amount of plant in existence. Therefore, the addition of plant to meet additional peak demands will give rise to additional operation and maintenance expense in proportion to the amount of plant added. In this sense, transmission O&M expenses are truly marginal costs.

Ontario Hydro has supplied forecasts for the 1976-1980 period of transmission O&M expenses for stations and lines. These expenses have been converted to 1975 dollars and unitized on the basis of forecast system peak demands. The unit expenses show a downward trend. We have reasoned that if rate stability is desirable - given no unanticipated changes in cost, load patterns or technology - a single estimate of these costs should be used in setting those rates. The 1978 level of expenses represents the midpoint of the period examined, and we have chosen the unit expense in that year as being the best estimate of these expenses for use in setting rates during the 1976-1980 period. This was a judgemental choice.

D. COMPUTATION OF ANNUAL CARRYING CHARGE

After developing the long-run marginal unit investments, it is necessary to determine how these investments should be converted into a marginal carrying charge for use in ratemaking. There are two approaches to the computation of annual carrying charges: the first is that traditionally utilized by engineers in evaluating alternative investments and the second is that used by the economist in simulating the effects of the competitive marketplace. In times of slight inflation and/or slight technical progress, the first method works well. However, the presence of

ONTARIO HYDRO
DERIVATION OF MARGINAL INVESTMENT IN TRANSMISSION FACILITIES
PER ADDED KILOWATT OF SYSTEM PEAK DEMAND

		Gross Additions to Electric Plant in Service						
		Stations			Lines			
	Year	115 KV[1]	230 KV[1]	EHV	115 KV	230 KV	EHV	Total
		(Thousand 1975 Dollars)						
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
(1)	1975	$2,081	$ 24,903	$ 398	$14,801	$ 48,758	$ 9,448	$ 100,389
(2)	1976	1,796	36,502	3,557	12,988	26,986	46,181	128,010
(3)	1977	2,703	35,856	11,404	10,328	37,229	96,405	193,925
(4)	1978	2,031	45,532	76,527	11,553	54,519	262,278	452,440
(5)	1979	762	22,855	111,153	6,352	47,548	50,839	239,509
(6)	1980	296	24,799	27,404	5,585	32,609	107,951	198,644
(7)	Total	$9,669	$190,447	$230,443	$61,607	$247,649	$573,102	$1,312,917
(8)	Additions to System Peak Demand 1975-1980 (Mw)							7,814
(9)	Marginal Investment per Added Kilowatt of System Peak Demand							$ 168

[1]Excludes station investment not related to bulk power transmission system.

Source: Based on data supplied by Ontario Hydro.

ONTARIO HYDRO
TRANSMISSION EXPENSE PER KW OF SYSTEM PEAK DEMAND

1976 - 1980

Year	Operation and Maintenance Expense Including Overheads for Stations[1] (Thousand Dollars) (1)	Electric Operation and Maintenance Index for Stations[2] (1975=100) (2)	Operation and Maintenance Expense Including Overheads for Stations (Thousand 1975 Dollars) [(1) ÷ (2)] x100 (3)	Operation and Maintenance Expense Including Overheads for Lines (Thousand Dollars) (4)	Electric Operation and Maintenance Index for Lines[2] (1975=100) (5)	Operation and Maintenance Expense Including Overheads for Lines (Thousand 1975 Dollars) [(4) ÷ (5)] x100 (6)	Total Operation and Maintenance Expense Including Overheads for Stations and Lines (Thousand 1975 Dollars) (3)+(6) (7)	System Peak Demand (Mw) (8)	Expense per Kw of System Peak Demand (1975 Dollars) (7) ÷ (8) (9)
1976	$15,019	110	$13,654	$8,755	109	$8,032	$21,686	16,208	$1.34
1977	17,566	122	14,398	9,947	120	8,289	22,687	17,605	1.29
1978	19,767	136	14,535	11,122	134	8,300	22,835	19,078	1.20
1979	22,562	148	15,245	12,244	147	8,329	23,574	20,376	1.16
1980	25,432	162	15,699	13,520	160	8,450	24,149	21,723	1.11
Used in Study									$1.20

[1]Forecast station O&M expenses included expenses related to bulk power transmission and distribution. Based on a ratio developed by Ontario Hydro, expenses not related to bulk power transmission were excluded from the analysis.

[2]Electric operation and maintenance indexes supplied by Ontario Hydro for stations and for transmission and distribution lines were weighted 75 percent for labor and 25 percent for materials. The indexes on a base of 1974=100 were converted to a 1975=100 base.

Source: Columns (1), (4) and (8): Data supplied by Ontario Hydro.

either significant inflation and/or significant technical progress causes that method to yield a poor approximation of the marginal economic cost of having a machine for a year. It is for this reason that we recommend the use of the economist's approach to an annual carrying charge even though we have not utilized that approach in this report.

1. The Engineer's Approach

Engineering economists for utilities have long sought to evaluate potential investments based on the relative present value of all revenue requirements arising from these investments. In their calculations, they predict service lives and the dispersion pattern of retirements, and simulate the full set of accounting charges incurred by plant over its useful life.

In developing annual carrying charges, we have, in the past, found it useful to draw upon this approach. As no one suggests that customers should be assessed the full marginal cost of the investments required to provide the service that they demand at the time the investment is made, the marginal cost to the company over time is the set of charges that will result from the investment. These charges consist of depreciation and the cost of capital.

In making this type of computation, it is necessary to account for the fact that different types of plant have different physical and economic characteristics. This is reflected in different service lives and the expected dispersion pattern of retirements. The annual cash flow requirements calculated on a year-by-year basis will be higher in earlier years when the plant is at full value. Actually, the marginal costs arising from an investment will change from year to year. However, *for illustrative purposes*, we have computed a levelized annual carrying charge.

The levelized annual carrying charge has been developed based upon the present worth of the series of all revenue requirements arising from an investment and the present worth of the mean annual surviving investment over the life of the plant. While the calculation of the carrying charge is based upon a plant that is physically declining according to the dispersion pattern of retirements, the utility must maintain the plant at full value if it is to continue to provide service. To account for this concept of a ''continuing plant,'' the carrying charge is applied annually to the cost of the original placement, yielding an annualized cost that will enable the utility to recover the depreciation and return associated with the original placement and the replacement of retirements.

Levelized annual carrying charges were computed separately for CTUs and transmission investment. The survivor curve used for transmission investment reflects a weighted average of the expected dispersion pattern of retirements of investment in this function and an average service life of 43.5 years. For combustion turbines, an average service life of 30 years is used. Information used to develop these factors was supplied by Ontario Hydro. Based upon NERA's experience, an Iowa SQ survivor curve was used for CTU investment.

The revenue requirements in each year were the sum of straight line book depreciation and return on mean net investment. Ontario Hydro's forecast overall cost of capital of 10 per cent was used as the return on mean net investment. Mean net investment was calculated as mean annual survivors less the reserve for depreciation. The discount factor used to determine the present worth of revenue requirements and mean annual surviving investment was the overall cost of capital of 10 per cent. The levelized annual carrying charges are the present worth of the revenue requirements divided by the present worth of the surviving investment. They are, for each category as follows:

	Levelized Annual Carrying Charge
CTU	10.61%
Transmission	10.50%

Schedule IV-D-1, Tables A and B show the detailed computations for each category.

2. The Economist's Approach

The economic cost of having a machine for a year is best measured by the annual rent that the businessman would charge in the competitive marketplace. This rental cost would consist of two components, a fair return on the value of the machine and any change in value of the machine over the year.

Assuming that a piece of equipment lasts for 30 years and retains full capability over its life, what is the change in the value of this equipment over a year in its life? Before answering, further assume that maintenance costs do not increase with age. Why, then, should the equipment change in value from year to year? It changes in value because the point at which it has to be replaced is approaching. The change in value in any year, therefore, is the difference between what the plant is worth at the beginning of the year and what it is worth at the end, given that the only factor affecting the value of the plant is that replacement must take place earlier for the older plant.

This annual change in value as a plant moves closer to the date at which it must be replaced is called ''economic depreciation''. If technical progress is expected, this charge will reflect the fact that by making the investment today, a certain price reduction is foregone. By parallel reasoning, if inflation is expected, the ''economic depreciation'' charge will reflect the fact that by making the investment today, a price increase is forgone.

A fair return on the value of the investment is the cost of capital times the value of the net investment. The net investment is the original investment less the change in value (''economic depreciation'').

When there is no expected inflation or technical progress, the cash flows resulting from using economic depreciation and the return on the net value of the investment will be identical to the cash flows obtained from the application of a levelized annual carrying charge. When technical progress outweighs inflation, the cash flows based on the use of ''economic depreciation'' will be higher in the earlier years and lower in the later years of the project's life than the levelized revenue requirement. In the face of inflation, the cash flows resulting from the use of ''economic depreciation'' will be lower in the early years of an investment and higher in the later years. In all cases, the sum of the present value of the revenue requirements will equal the present value of the investment.

If there is an expectation of inflation net of technical progress, the stream of required revenues will rise over time at this rate of inflation. This simulates the pattern of payments that would occur in a competitive marketplace, where investors will seek a return on the value of their investment and will recognize any real change in value resulting from an increase in the price of the investment in evaluating the investment and in determining the rental price they they can expect.

SCHEDULE IV-D-1
TABLE A

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
CTU PRODUCTION

								PRESENT VALUE		
YEAR	MEAN ANNUAL SURVIVORS	BOOK DEPRE- CIATION	RETIRE- MENTS	BOOK DEPRE- CIATION RESERVE	MEAN NET IN- VESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	$1 AT 10.00%	ORIGINAL MEAN ANNUAL SURVIVORS	REVENUE REQUIREMENT
		3.33%*(1)			(1)-(4)	10.00%*(5)	(2)+(6)		(1)*(8)	(7)*(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	1000	33.33	0.00	0.00	1000.00	100.00	133.33	0.9091	909.09	121.21
2	1000	33.33	0.00	33.33	966.67	96.67	130.00	0.8264	826.45	107.44
3	1000	33.33	0.00	66.67	933.33	93.33	126.67	0.7513	751.31	95.17
4	1000	33.33	0.00	100.00	900.00	90.00	123.33	0.6830	683.01	84.24
5	1000	33.33	0.00	133.33	866.67	86.67	120.00	0.6209	620.92	74.51
6	1000	33.33	0.00	166.67	833.33	83.33	116.67	0.5645	564.47	65.86
7	1000	33.33	0.00	200.00	800.00	80.00	113.33	0.5132	513.16	58.16
8	1000	33.33	0.00	233.33	766.67	76.67	110.00	0.4665	466.51	51.32
9	1000	33.33	0.00	266.67	733.33	73.33	106.67	0.4241	424.10	45.24
10	1000	33.33	0.00	300.00	700.00	70.00	103.33	0.3855	385.54	39.84
11	1000	33.33	0.00	333.33	666.67	66.67	100.00	0.3505	350.49	35.05
12	1000	33.33	0.00	366.67	633.33	63.33	96.67	0.3186	318.63	30.80
13	1000	33.33	0.00	400.00	600.00	60.00	93.33	0.2897	289.66	28.04
							90.00	0.2633	263.33	25.70
14	1000	33.33	0.00	433.33	566.67	56.67	86.67	0.2394	239.39	20.75
15	1000	33.33	0.00	466.67	533.33	53.33	83.33	0.2176	217.63	18.14
16	1000	33.33	0.00	500.00	500.00	50.00	80.00	0.1978	197.84	15.83
17	1000	33.33	0.00	533.33	466.67	46.67	76.67	0.1799	179.86	13.79
18	1000	33.33	0.00	566.67	433.33	43.33	73.33	0.1635	163.51	11.99
19	1000	33.33	0.00	600.00	400.00	40.00	70.00	0.1486	148.64	10.41
20	1000	33.33	0.00	633.33	366.67	36.67	66.67	0.1351	135.13	9.01
21	1000	33.33	0.00	666.67	333.33	33.33	63.33	0.1228	122.85	7.78
22	1000	33.33	0.00	700.00	300.00	30.00	60.00	0.1117	111.68	6.70
23	1000	33.33	0.00	733.33	266.67	26.67	56.67	0.1015	101.53	5.75
24	1000	33.33	0.00	766.67	233.33	23.33	53.33	0.0923	92.30	4.92
25	1000	33.33	0.00	800.00	200.00	20.00	50.00	0.0839	83.91	4.20
26	1000	33.33	0.00	833.33	166.67	16.67	46.67	0.0763	76.28	3.56
27	1000	33.33	0.00	866.67	133.33	13.33	43.33	0.0693	69.34	3.00
28	1000	33.33	0.00	900.00	100.00	10.00	40.00	0.0630	63.04	2.52
29	1000	33.33	0.00	933.33	66.67	6.67	36.67	0.0573	57.31	2.10
30	1000	33.33	0.00	966.67	33.33	3.33				
									9,426.91	1,000.00

THE LEVELIZED ANNUAL REVENUE REQUIREMENT RELATING TO AN INCREMENTAL INVESTMENT OF $1000 IS 10.6079 %

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
TRANSMISSION

YEAR	MEAN ANNUAL SURVIVORS	BOOK DEPRE-CIATION	RETIRE-MENTS	BOOK DEPRE-CIATION RESERVE	MEAN NET IN-VESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	PRESENT VALUE: $1 AT 10.00%	PRESENT VALUE: ORIGINAL MEAN ANNUAL SURVIVORS	PRESENT VALUE: REVENUE REQUIREMENT
		2.30%*(1)			(1)-(4)	10.00%*(5)	(2)+(6)		(1)*(8)	(7)*(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	1000	22.99	1.00	0.00	1000.00	100.00	122.99	0.9091	909.09	111.81
2	999	22.97	0.00	21.99	977.01	97.70	120.67	0.8264	825.62	99.72
3	999	22.97	1.00	44.95	954.05	95.40	118.37	0.7513	750.56	88.93
4	998	22.94	1.00	66.92	931.08	93.11	116.05	0.6830	681.65	79.26
5	997	22.92	2.00	88.86	908.14	90.81	113.73	0.6209	619.06	70.62
6	995	22.87	1.00	109.78	885.22	88.52	111.40	0.5645	561.65	62.88
7	994	22.85	2.00	131.66	862.34	86.23	109.09	0.5132	510.08	55.98
8	992	22.80	2.00	152.51	839.49	83.95	106.75	0.4665	462.78	49.80
9	990	22.76	3.00	173.31	816.69	81.67	104.43	0.4241	419.86	44.29
10	987	22.69	3.00	193.07	793.93	79.39	102.08	0.3855	380.53	39.36
11	984	22.62	4.00	212.76	771.24	77.12	99.74	0.3505	344.89	34.96
12	980	22.53	4.00	231.38	748.62	74.86	97.39	0.3186	312.26	31.03
13	976	22.44	5.00	249.91	726.09	72.61	95.05	0.2897	282.71	27.53
14	971	22.32	5.00	267.34	703.66	70.37	92.69	0.2633	255.69	24.41
15	966	22.21	6.00	284.67	681.33	68.13	90.34	0.2394	231.25	21.63
16	960	22.07	7.00	300.87	659.13	65.91	87.98	0.2176	208.92	19.15
17	953	21.91	8.00	315.94	637.06	63.71	85.61	0.1978	188.55	16.94
18	945	21.72	9.00	329.85	615.15	61.51	83.24	0.1799	169.97	14.97
19	936	21.52	8.00	342.57	593.43	59.34	80.86	0.1635	153.64	13.22
20	928	21.33	11.00	356.09	571.91	57.19	78.52	0.1486	137.94	11.67
21	917	21.08	11.00	366.43	550.57	55.06	76.14	0.1351	123.91	10.29
22	906	20.83	12.00	376.51	529.49	52.95	73.78	0.1228	111.30	9.06
23	894	20.55	13.00	385.33	508.67	50.87	71.42	0.1117	99.84	7.98
24	881	20.25	13.00	392.89	488.11	48.81	69.06	0.1015	89.44	7.01
25	868	19.95	14.00	400.14	467.86	46.79	66.74	0.0923	80.11	6.16
26	854	19.63	15.00	406.09	447.91	44.79	64.42	0.0839	71.66	5.41
27	839	19.29	16.00	410.72	428.28	42.83	62.11	0.0763	64.00	4.74
28	823	18.92	17.00	414.01	408.99	40.90	59.82	0.0693	57.07	4.15
29	806	18.53	16.00	415.93	390.07	39.01	57.54	0.0630	50.81	3.63
30	790	18.16	18.00	418.46	371.54	37.15	55.31	0.0573	45.27	3.17
31	772	17.75	18.00	418.62	353.38	35.34	53.09	0.0521	40.22	2.77
32	754	17.33	19.00	418.37	335.63	33.56	50.90	0.0474	35.71	2.41
33	735	16.90	20.00	416.70	318.30	31.83	48.73	0.0431	31.65	2.10
34	715	16.44	20.00	413.60	301.40	30.14	46.58	0.0391	27.99	1.82
35	695	15.98	20.00	410.03	284.97	28.50	44.47	0.0356	24.73	1.58
36	675	15.52	21.00	406.01	268.99	26.90	42.42	0.0323	21.84	1.37
37	654	15.03	21.00	400.53	253.47	25.35	40.38	0.0294	19.23	1.19
38	633	14.55	22.00	394.56	238.44	23.84	38.40	0.0267	16.92	1.03
39	611	14.05	21.00	387.11	223.89	22.39	36.43	0.0243	14.85	0.89
40	590	13.56	22.00	380.16	209.84	20.98	34.55	0.0221	13.04	0.76
41	568	13.06	23.00	371.72	196.28	19.63	32.69	0.0201	11.41	0.66
42	545	12.53	22.00	361.78	183.22	18.32	30.85	0.0183	9.95	0.56
43	523	12.02	22.00	352.31	170.69	17.07	29.09	0.0166	8.68	0.48
44	501	11.52	23.00	342.33	158.67	15.87	27.38	0.0151	7.56	0.41
45	478	10.99	22.00	330.85	147.15	14.71	25.70	0.0137	6.56	0.35
46	456	10.48	22.00	319.84	136.16	13.62	24.10	0.0125	5.69	0.30
47	434	9.98	23.00	308.32	125.68	12.57	22.54	0.0113	4.92	0.26

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
TRANSMISSION

								PRESENT VALUE		
YEAR	MEAN ANNUAL SURVIVORS	BOOK DEPRE-CIATION	RETIRE-MENTS	BOOK DEPRE-CIATION RESERVE	MEAN NET IN-VESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	$1 AT 10.00%	ORIGINAL MEAN ANNUAL SURVIVORS	REVENUE REQUIREMENT
		2.30%*(1)			(1)-(4)	10.00%*(5)	(2)+(6)		(1)*(8)	(7)*(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
48	411	9.45	22.00	295.30	115.70	11.57	21.02	0.0103	4.24	0.22
49	389	8.94	22.00	282.75	106.25	10.63	19.57	0.0094	3.65	0.18
50	367	8.44	21.00	269.69	97.31	9.73	18.17	0.0085	3.13	0.15
51	346	7.95	21.00	257.13	88.87	8.89	16.84	0.0077	2.68	0.13
52	325	7.47	21.00	244.08	80.92	8.09	15.56	0.0070	2.29	0.11
53	304	6.99	20.00	230.55	73.45	7.34	14.33	0.0064	1.95	0.09
54	284	6.53	20.00	217.54	66.46	6.65	13.17	0.0058	1.65	0.08
55	264	6.07	19.00	204.07	59.93	5.99	12.06	0.0053	1.40	0.06
56	245	5.63	18.00	191.14	53.86	5.39	11.02	0.0048	1.18	0.05
57	227	5.22	18.00	178.77	48.23	4.82	10.04	0.0044	0.99	0.04
58	209	4.80	17.00	165.99	43.01	4.30	9.11	0.0040	0.83	0.04
59	192	4.41	17.00	153.79	38.21	3.82	8.23	0.0036	0.69	0.03
60	175	4.02	15.00	141.21	33.79	3.38	7.40	0.0033	0.57	0.02
61	160	3.68	15.00	130.23	29.77	2.98	6.66	0.0030	0.48	0.02
62	145	3.33	14.00	118.91	26.09	2.61	5.94	0.0027	0.39	0.02
63	131	3.01	13.00	108.24	22.76	2.28	5.29	0.0025	0.32	0.01
64	118	2.71	13.00	98.25	19.75	1.97	4.69	0.0022	0.26	0.01
65	105	2.41	11.00	87.97	17.03	1.70	4.12	0.0020	0.21	0.01
66	94	2.16	11.00	79.38	14.62	1.46	3.62	0.0019	0.17	0.01
67	83	1.91	10.00	70.54	12.46	1.25	3.15	0.0017	0.14	0.01
68	73	1.68	8.00	62.45	10.55	1.06	2.73	0.0015	0.11	0.00
69	65	1.49	9.00	56.13	8.87	0.89	2.38	0.0014	0.09	0.00
70	56	1.29	8.00	48.62	7.38	0.74	2.03	0.0013	0.07	0.00
71	48	1.10	6.00	41.91	6.09	0.61	1.71	0.0012	0.06	0.00
72	42	0.97	6.00	37.01	4.99	0.50	1.46	0.0010	0.04	0.00
73	36	0.83	6.00	31.98	4.02	0.40	1.23	0.0010	0.03	0.00
74	30	0.69	5.00	26.80	3.20	0.32	1.01	0.0009	0.03	0.00
75	25	0.57	3.00	22.49	2.51	0.25	0.83	0.0008	0.02	0.00
76	22	0.51	4.00	20.07	1.93	0.19	0.70	0.0007	0.02	0.00
77	18	0.41	3.00	16.57	1.43	0.14	0.56	0.0006	0.01	0.00
78	15	0.34	3.00	13.99	1.01	0.10	0.45	0.0006	0.01	0.00
79	12	0.28	2.00	11.33	0.67	0.07	0.34	0.0005	0.01	0.00
80	10	0.23	2.00	9.61	0.39	0.04	0.27	0.0005	0.00	0.00
81	8	0.18	2.00	7.84	0.16	0.02	0.20	0.0004	0.00	0.00
82	6	0.14	1.00	6.62	-0.02	-0.00	0.14	0.0004	0.00	0.00
83	5	0.11	1.00	5.16	-0.16	-0.02	0.10	0.0004	0.00	0.00
84	4	0.09	1.00	4.28	-0.28	-0.03	0.06	0.0003	0.00	0.00
85	3	0.07	0.00	3.37	-0.37	-0.04	0.03	0.0003	0.00	0.00
86	3	0.07	1.00	3.44	-0.44	-0.04	0.03	0.0003	0.00	0.00
87	2	0.05	0.00	2.51	-0.51	-0.05	-0.00	0.0003	0.00	-0.00
88	2	0.05	1.00	2.55	-0.55	-0.06	-0.01	0.0002	0.00	-0.00
89	1	0.02	0.00	1.60	-0.60	-0.06	-0.04	0.0002	0.00	-0.00
90	1	0.02	0.00	1.62	-0.62	-0.06	-0.04	0.0002	0.00	-0.00
91	1	0.02	0.00	1.64	-0.64	-0.06	-0.04	0.0002	0.00	-0.00
92	1	0.02	0.00	1.67	-0.67	-0.07	-0.04	0.0002	0.00	-0.00
93	1	0.02	0.00	1.69	-0.69	-0.07	-0.05	0.0001	0.00	-0.00
94	1	0.02	0.00	1.71	-0.71	-0.07	-0.05	0.0001	0.00	-0.00
									9,528.20	1,000.00

THE LEVELIZED ANNUAL REVENUE REQUIREMENT RELATING TO AN INCREMENTAL INVESTMENT OF $1000 IS 10.4952 %

We have calculated annual charges which are based on this simulation of the competitive marketplace. A brief description of the methodology used to calculate these annual charges follows.

In analyzing electric utility investment, it is necessary to account for the fact that different types of plant have different physical and economic characteristics. These characteristics, service life and retirement dispersion pattern, are discussed earlier in the study.

The fact that retirements are dispersed around the average life reflects the fact that the plant is not at full output over its in-service period. In calculating an economic series of carrying charges, this fact has been corrected for by considering the replacement of retirements as maintenance cost. The cost of replacing the retirements in inflated dollars has been discounted to the time of the original investment, and the carrying charge relative to an original investment of $1,000 has been calculated on the value of the original $1,000 investment and the present value of the inflated cost of the replacement of retirements over the full service life of the investment.

The rate of inflation (net of technical progress) has been taken as 4 per cent. Examining economic depreciation in the face of inflation, it can be seen that in the early years of an investment, equipment experiences negative depreciation, an appreciation in value. The annual revenue requirement has been calculated as the sum of depreciation and overall return on net investment. Net investment is calculated as gross investment less the depreciation reserve. Thus, in the early years, as equipment rises in true value, the return on investment increases and the depreciation allowance is negative.

The annual revenue requirement rises by the rate of inflation. The net present value of the annual revenue requirements equals the net present value of all costs associated with the original investment. The rental charge in any year equals the undiscounted value of the revenue requirement. The percentage carrying charge represented in 1975 dollars is the first year's revenue requirement divided by the value of the original placement of $1,000. Schedule IV-D-2, Tables A and B show in a detailed fashion this method of computing annual charges.

	Simulation of Competitive Marketplace Annual Carrying Charge
CTU	7.37%
Transmission	6.86%

While these results represent an appropriate theoretical calculation of "economic depreciation", it is not completely consistent with certain real world factors that appear to affect price formation in many competitive markets. In particular, predictions of the rate of inflation and technical progress become more and more uncertain as we go further out into the future. Either because of risk aversion or because of an inability to fully diversify such risks, nonregulated firm appear to give even greater relative weight to early periods than would be implied by the discount rate used in the above calculation. From the businessman's perspective, this appears as a shorter target payback period than would be implied by the discount rate used in the above calculation. Since these factors influence investment and pricing behaviour by firms producing goods and services that are substitutes and complements for electricity, we believe that such considerations must also be factored into our attempt to simulate the effective competitive carrying charge used to calculate the marginal costs on which electricity prices will be based.

This shortened period, although it differs for every corporation and type of equipment, could in the United States be thought of as the lower limit of the asset depreciation accelerated tax lives allowed by the Internal Revenue Service. To compute marginal costs that more accurately reflect what competitors are doing, the time period over which to recover the present value of the revenue requirements can be changed from the book life of the project to the tax life described above. We would like to explore this subject further with Ontario Hydro personnel in order to find a Canadian basis for determining this shortened period.

We are not recommending that Ontario Hydro suddenly convert to this type of analysis to value plant and determine overall revenue requirements. We do believe, however, that to make the marginal costs and prices of electricity consistent with those arising in the marketplace in general, an economic approach to calculating the carrying charge, such as that described above, must be utilized. We do recognize that calculations based on this approach are quite sensitive to assumptions about the rate of inflation, technological change and the appropriate payback period to the extent that it differs from that implied by the cost of capital above. Since capacity costs are such a large proportion of total costs, the specific calculation utilized will have to be examined on a case-by-case basis although the basic methodology will remain unchanged.

E. COMPUTATION OF MARGINAL UNIT DEMAND-RELATED COSTS

As previously described, we have developed annual carrying charge factors to convert marginal long-run unit investments into marginal unit demand-related costs. These factors provide for the return of and the return on capital. There are, however, other costs associated with the annual marginal capacity cost of supplying electric service. These are property-related taxes, demand-related operation and maintenance expenses, and a return on materials and supplies that must be kept in stock as part of the cost of providing electric service.

These costs are all marginal in nature. As demand increases, the utility faces the long-run marginal investments occasioned by the increases in demand. These investments lead to increases in property taxes based on the marginal value of the investment and the need for incremental inventories of materials and supplies to support the investment. Similarly, as previously described, the continuance of demand leads to marginal demand-related operation and maintenance expenses that, over the long run, will vary as demand varies.

To calculate the annual unit demand-related cost, we have added a property tax rate of 0.2 per cent of gross plant to the annual carrying charge. The resulting figure was then multiplied by the long-run unit investment in each function to arrive at an annualized plant cost in dollars per kilowatt. The annual demand-related operation and maintenance expense was added to the annualized plant cost. No demand-related operation and maintenance expense has been included for combustion turbines because no recent analysis of Ontario Hydro's experience was available at this writing. Materials and supplies were estimated based upon NERA's experience to be 2 per cent of gross

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
CTU PRODUCTION

YEAR	MEAN ANNUAL SURVIVORS	ECONOMIC DEPRECIATION	RETIREMENTS	DEPRECIATION RESERVE	MEAN NET INVESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	PRESENT VALUE $1 AT 10.00%	PRESENT VALUE REVENUE REQUIREMENT
	(1)	(2)	(3)	(4)	(1)-(4) (5)	10.00%*(5) (6)	(2)+(6) (7)	(8)	(7)*(8) (9)
1975	1000.00	-26.30	0.00	0.00	1000.00	100.00	73.70	0.9091	67.00
1976	1000.00	-25.98	0.00	-26.30	1026.30	102.63	76.65	0.8264	63.34
1977	1000.00	-25.52	0.00	-52.28	1052.28	105.23	79.71	0.7513	59.89
1978	1000.00	-24.88	0.00	-77.80	1077.80	107.78	82.90	0.6830	56.62
1979	1000.00	-24.05	0.00	-102.68	1102.68	110.27	86.22	0.6209	53.53
1980	1000.00	-23.01	0.00	-126.73	1126.73	112.67	89.67	0.5645	50.61
1981	1000.00	-21.72	0.00	-149.74	1149.74	114.97	93.25	0.5132	47.85
1982	1000.00	-20.16	0.00	-171.46	1171.46	117.15	96.98	0.4665	45.24
1983	1000.00	-18.30	0.00	-191.62	1191.62	119.16	100.86	0.4241	42.78
1984	1000.00	-16.10	0.00	-209.92	1209.92	120.99	104.90	0.3855	40.44
1985	1000.00	-13.51	0.00	-226.02	1226.02	122.60	109.09	0.3505	38.24
1986	1000.00	-10.50	0.00	-239.53	1239.53	123.95	113.46	0.3186	36.15
1987	1000.00	-7.01	0.00	-250.03	1250.03	125.00	117.99	0.2897	34.18
1988	1000.00	-2.99	0.00	-257.04	1257.04	125.70	122.71	0.2633	32.31
1989	1000.00	1.62	0.00	-260.03	1260.03	126.00	127.62	0.2394	30.55
1990	1000.00	6.89	0.00	-258.41	1258.41	125.84	132.73	0.2176	28.89
1991	1000.00	12.88	0.00	-251.52	1251.52	125.15	138.04	0.1978	27.31
1992	1000.00	19.69	0.00	-238.63	1238.63	123.86	143.56	0.1799	25.82
1993	1000.00	27.41	0.00	-218.94	1218.94	121.89	149.30	0.1635	24.41
1994	1000.00	36.12	0.00	-191.53	1191.53	119.15	155.27	0.1486	23.08
1995	1000.00	45.94	0.00	-155.42	1155.42	115.54	161.49	0.1351	21.82
1996	1000.00	56.99	0.00	-109.47	1109.47	110.95	167.94	0.1228	20.63
1997	1000.00	69.41	0.00	-52.48	1052.48	105.25	174.66	0.1117	19.51
1998	1000.00	83.34	0.00	16.93	983.07	98.31	181.65	0.1015	18.44
1999	1000.00	98.94	0.00	100.27	899.73	89.97	188.91	0.0923	17.44
2000	1000.00	116.39	0.00	199.21	800.79	80.08	196.47	0.0839	16.48
2001	1000.00	135.89	0.00	315.60	684.40	68.44	204.33	0.0763	15.59
2002	1000.00	157.65	0.00	451.49	548.51	54.85	212.50	0.0693	14.74
2003	1000.00	181.91	0.00	609.14	390.86	39.09	221.00	0.0630	13.93
2004	1000.00	208.95	0.00	791.05	208.95	20.89	229.84	0.0573	13.17
									1,000.00

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
TRANSMISSION

YEAR	MEAN ANNUAL SURVIVORS	ECONOMIC DEPRECIATION	RETIREMENTS	DEPRECIATION RESERVE	MEAN NET INVESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	PRESENT VALUE: $1 AT 10.00%	PRESENT VALUE: REVENUE REQUIREMENT
					(1)-(4)	10.00%*(5)	(2)+(6)		(7)*(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1975	1137.52	-45.15	0.00	0.00	1137.52	113.75	68.60	0.9091	62.37
1976	1137.52	-46.92	0.00	-45.15	1182.67	118.27	71.35	0.8264	58.96
1977	1137.52	-48.76	0.00	-92.07	1229.59	122.96	74.20	0.7513	55.75
1978	1137.52	-50.67	0.00	-140.83	1278.35	127.83	77.17	0.6830	52.71
1979	1137.52	-52.65	0.00	-191.49	1329.01	132.90	80.26	0.6209	49.83
1980	1137.52	-54.70	0.00	-244.14	1381.66	138.17	83.47	0.5645	47.11
1981	1137.52	-56.83	0.00	-298.84	1436.36	143.64	86.81	0.5132	44.54
1982	1137.52	-59.04	0.00	-355.67	1493.19	149.32	90.28	0.4665	42.11
1983	1137.52	-61.33	0.00	-414.71	1552.23	155.22	93.89	0.4241	39.82
1984	1137.52	-63.71	0.00	-476.04	1613.56	161.36	97.64	0.3855	37.65
1985	1137.52	-66.18	0.00	-539.76	1677.28	167.73	101.55	0.3505	35.59
1986	1137.52	-68.73	0.00	-605.93	1743.45	174.35	105.61	0.3186	33.65
1987	1137.52	-71.38	0.00	-674.67	1812.19	181.22	109.84	0.2897	31.82
1988	1137.52	-74.13	0.00	-746.05	1883.57	188.36	114.23	0.2633	30.08
1989	1137.52	-76.97	0.00	-820.18	1957.70	195.77	118.80	0.2394	28.44
1990	1137.52	-79.92	0.00	-897.15	2034.67	203.47	123.55	0.2176	26.89
1991	1137.52	-82.97	0.00	-977.06	2114.59	211.46	128.49	0.1978	25.42
1992	1137.52	-86.12	0.00	-1060.03	2197.55	219.76	133.63	0.1799	24.03
1993	1137.52	-89.39	0.00	-1146.15	2283.67	228.37	138.98	0.1635	22.72
1994	1137.52	-92.77	0.00	-1235.54	2373.06	237.31	144.54	0.1486	21.48
1995	1137.52	-96.27	0.00	-1328.31	2465.83	246.58	150.32	0.1351	20.31
1996	1137.52	-99.88	0.00	-1424.58	2562.10	256.21	156.33	0.1228	19.20
1997	1137.52	-103.61	0.00	-1524.46	2661.98	266.20	162.58	0.1117	18.16
1998	1137.52	-107.47	0.00	-1628.07	2765.59	276.56	169.09	0.1015	17.17
1999	1137.52	-111.46	0.00	-1735.54	2873.06	287.31	175.85	0.0923	16.23
2000	1137.52	-115.57	0.00	-1847.00	2984.52	298.45	182.89	0.0839	15.35
2001	1137.52	-119.81	0.00	-1962.56	3100.08	310.01	190.20	0.0763	14.51
2002	1137.52	-124.18	0.00	-2082.37	3219.89	321.99	197.81	0.0693	13.72
2003	1137.52	-128.69	0.00	-2206.55	3344.07	334.41	205.72	0.0630	12.97
2004	1137.52	-133.33	0.00	-2335.24	3472.76	347.28	213.95	0.0573	12.26
2005	1137.52	-138.10	0.00	-2468.57	3606.09	360.61	222.51	0.0521	11.59
2006	1137.52	-143.01	0.00	-2606.67	3744.19	374.42	231.41	0.0474	10.96
2007	1137.52	-148.06	0.00	-2749.68	3887.20	388.72	240.66	0.0431	10.36
2008	1137.52	-153.23	0.00	-2897.73	4035.25	403.53	250.29	0.0391	9.80
2009	1137.52	-158.55	0.00	-3050.97	4188.49	418.85	260.30	0.0356	9.26
2010	1137.52	-163.99	0.00	-3209.51	4347.03	434.70	270.71	0.0323	8.76
2011	1137.52	-169.56	0.00	-3373.50	4511.02	451.10	281.54	0.0294	8.28
2012	1137.52	-175.25	0.00	-3543.06	4680.58	468.06	292.80	0.0267	7.83
2013	1137.52	-181.07	0.00	-3718.31	4855.84	485.58	304.52	0.0243	7.40
2014	1137.52	-186.99	0.00	-3899.38	5036.90	503.69	316.70	0.0221	7.00
2015	1137.52	-193.03	0.00	-4086.37	5223.89	522.39	329.37	0.0201	6.62
2016	1137.52	-199.15	0.00	-4279.40	5416.92	541.69	342.54	0.0183	6.25
2017	1137.52	-205.36	0.00	-4478.55	5616.07	561.61	356.24	0.0166	5.91
2018	1137.52	-211.65	0.00	-4683.91	5821.43	582.14	370.49	0.0151	5.59

ONTARIO HYDRO
CALCULATION OF REVENUE REQUIREMENTS
RELATED TO INCREMENTAL CAPITAL INVESTMENT
TRANSMISSION

YEAR	MEAN ANNUAL SURVIVORS	ECO-NOMIC DEPRE-CIATION	RETIRE-MENTS	DEPRE-CIATION RESERVE	MEAN NET IN-VESTMENT	INTEREST AND EQUITY RETURN	REVENUE REQUIREMENT	PRESENT VALUE $1 AT 10.00%	PRESENT VALUE REVENUE REQUIREMENT
					(1)-(4)	10.00%*(5)	(2)+(6)		(7)*(8)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
2019	1137.52	-218.00	0.00	-4895.56	6033.09	603.31	385.31	0.0137	5.29
2020	1137.52	-224.38	0.00	-5113.56	6251.08	625.11	400.72	0.0125	5.00
2021	1137.52	-230.79	0.00	-5337.95	6475.47	647.55	416.75	0.0113	4.73
2022	1137.52	-237.20	0.00	-5568.74	6706.26	670.63	433.42	0.0103	4.47
2023	1137.52	-243.59	0.00	-5805.94	6943.46	694.35	450.76	0.0094	4.22
2024	1137.52	-249.91	0.00	-6049.53	7187.05	718.71	468.79	0.0085	3.99
2025	1137.52	-256.15	0.00	-6299.44	7436.97	743.70	487.54	0.0077	3.78
2026	1137.52	-262.27	0.00	-6555.60	7693.12	769.31	507.04	0.0070	3.57
2027	1137.52	-268.21	0.00	-6817.87	7955.39	795.54	527.33	0.0064	3.37
2028	1137.52	-273.94	0.00	-7086.08	8223.60	822.36	548.42	0.0058	3.19
2029	1137.52	-279.40	0.00	-7360.02	8497.55	849.75	570.35	0.0053	3.02
2030	1137.52	-284.53	0.00	-7639.42	8776.94	877.69	593.17	0.0048	2.85
2031	1137.52	-289.25	0.00	-7923.95	9061.47	906.15	616.90	0.0044	2.70
2032	1137.52	-293.50	0.00	-8213.20	9350.72	935.07	641.57	0.0040	2.55
2033	1137.52	-297.19	0.00	-8506.70	9644.22	964.42	667.23	0.0036	2.41
2034	1137.52	-300.22	0.00	-8803.89	9941.41	994.14	693.92	0.0033	2.28
2035	1137.52	-302.48	0.00	-9104.11	10241.63	1024.16	721.68	0.0030	2.15
2036	1137.52	-303.86	0.00	-9406.59	10544.11	1054.41	750.55	0.0027	2.04
2037	1137.52	-304.23	0.00	-9710.45	10847.97	1084.80	780.57	0.0025	1.93
2038	1137.52	-303.43	0.00	-10014.68	11152.20	1115.22	811.79	0.0022	1.82
2039	1137.52	-301.30	0.00	-10318.10	11455.62	1145.56	844.26	0.0020	1.72
2040	1137.52	-297.66	0.00	-10619.40	11756.92	1175.69	878.04	0.0019	1.63
2041	1137.52	-292.30	0.00	-10917.06	12054.58	1205.46	913.16	0.0017	1.54
2042	1137.52	-285.01	0.00	-11209.36	12346.88	1234.69	949.68	0.0015	1.46
2043	1137.52	-275.52	0.00	-11494.36	12631.89	1263.19	987.67	0.0014	1.38
2044	1137.52	-263.56	0.00	-11769.88	12907.40	1290.74	1027.18	0.0013	1.30
2045	1137.52	-248.83	0.00	-12033.45	13170.97	1317.10	1068.26	0.0012	1.23
2046	1137.52	-230.99	0.00	-12282.28	13419.80	1341.98	1110.99	0.0010	1.16
2047	1137.52	-209.64	0.00	-12513.26	13650.78	1365.08	1155.43	0.0010	1.10
2048	1137.52	-184.39	0.00	-12722.91	13860.43	1386.04	1201.65	0.0009	1.04
2049	1137.52	-154.76	0.00	-12907.30	14044.82	1404.48	1249.72	0.0008	0.98
2050	1137.52	-120.25	0.00	-13062.06	14199.58	1419.96	1299.71	0.0007	0.93
2051	1137.52	-80.29	0.00	-13182.31	14319.84	1431.98	1351.69	0.0006	0.88
2052	1137.52	-34.25	0.00	-13262.60	14400.12	1440.01	1405.76	0.0006	0.83
2053	1137.52	18.56	0.00	-13296.85	14434.37	1443.44	1461.99	0.0005	0.79
2054	1137.52	78.89	0.00	-13278.30	14415.82	1441.58	1520.47	0.0005	0.74
2055	1137.52	147.60	0.00	-13199.41	14336.93	1433.69	1581.29	0.0004	0.70
2056	1137.52	225.61	0.00	-13051.81	14189.33	1418.93	1644.54	0.0004	0.66
2057	1137.52	313.95	0.00	-12826.20	13963.72	1396.37	1710.33	0.0004	0.63
2058	1137.52	413.76	0.00	-12512.24	13649.76	1364.98	1778.74	0.0003	0.59
2059	1137.52	526.29	0.00	-12098.48	13236.00	1323.60	1849.89	0.0003	0.56
2060	1137.52	652.91	0.00	-11572.19	12709.71	1270.97	1923.88	0.0003	0.53
2061	1137.52	795.16	0.00	-10919.28	12056.80	1205.68	2000.84	0.0003	0.50
2062	1137.52	954.71	0.00	-10124.12	11261.64	1126.16	2080.87	0.0002	0.47
2063	1137.52	1133.41	0.00	-9169.41	10306.94	1030.69	2164.11	0.0002	0.45
2064	1137.52	1333.32	0.00	-8036.00	9173.52	917.35	2250.67	0.0002	0.42
2065	1137.52	1556.68	0.00	-6702.68	7840.20	784.02	2340.70	0.0002	0.40
2066	1137.52	1805.97	0.00	-5146.00	6283.52	628.35	2434.33	0.0002	0.38
2067	1137.52	2083.94	0.00	-3340.03	4477.55	447.76	2531.70	0.0001	0.36
2068	1137.52	2393.61	0.00	-1256.09	2393.61	239.36	2632.97	0.0001	0.34
									1,137.52

investment. The revenue requirement for materials and supplies is calculated using the Ontario Hydro cost of capital of 10 per cent and is added to the annualized plant cost and operation and maintenance expense to arrive at a total annualized marginal demand-related unit cost.

The results are as follows:

1.Generation: $20/kW

2.Transmission: $20/kW

The computations can be found on schedule IV-E-1.

F. MARGINAL DEMAND-RELATED COSTS BY PERIOD

The assignment of marginal capacity costs to different periods is intimately related to the process by which we select our rating periods. First, let us recognize that efficient system expansion requires long-run unit investment that adds capacity up to the point at which marginal capacity cost is equal to the expected marginal cost of shortage. Thus, the expected cost of shortage for a system with the optimal level of capacity can be expressed in terms of capacity costs. These costs can be assigned to different periods according to the relative probability of being in a shortage situation in each of the periods.

In Section III, we have described how costing periods were selected based on the relative values of LOLP. We have defined three costing periods - a peak-hour period for the winter and summer, and a year-round off-peak hour period. The off-peak hour period, as described in Section III, was judged to contribute very little to the expected probability of shortage and was not assigned any capacity costs.

The annualized marginal unit demand-related costs must, therefore, be assigned to the winter peak-hour and summer peak-hour periods based upon the relative probability of shortage in each period. Costing period capacity cost allocation factors are developed on Schedule IV-F-1, page 1. They are determined by weighting the average value of LOLP in each season by the number of peak hours in each season and calculating the seasonal relative value of this weighted figure. This process shows us that roughly 87 per cent of the annual probability of shortage occurs during the winter months and 13 per cent occurs during the summer months. Since capacity costs are properly assigned to periods according to the relative probability of being in a shortage situation in the period, we have allocated 87 per cent of the capacity costs to the winter peak hours and 13 per cent to the summer peak hours. These allocation factors are based on probability computations which, in a strict sense, are applicable only to the generation portion of the capacity costs. However, since the major portion of the transmission system is designed to meet the peak load, we believe that the allocation factors reasonably reflect the causality of costs on the transmission system.

The marginal demand-related costs per kilowatt have been adjusted by a factor of 5 per cent to account for energy lost at time of system peak between the customer and the generator. This adjustment converts the costs into a cost per kilowatt of peak demand as measured at the customer's meter and is suitable for use in ratemaking. It must be remembered that the capacity costs calculated have been based upon marginal costs per kilowatt of system peak demand. However, when making rates, we would more likely want a cost per kilowatt of mean seasonal peak demand. On Schedule IV-F-1, page 2, we have calculated the ratio of mean seasonal peak demand to annual system peak demand.

The period capacity cost per kilowatt of mean seasonal demand is calculated by multiplying the marginal demand-related cost by the period capacity cost allocation factor and dividing the result by the value of mean seasonal peak demand relative to annual system peak demand. Period demand-related costs calculated in such a way and charged according to contribution or probable contribution to mean seasonal peak demand will yield the required revenue for system expansion to meet capacity needs at time of peak.

These computations and the resulting marginal capacity-related costs per kilowatt of mean seasonal peak demand of $38.06 for the winter peak hours and $6.34 for the summer peak hours are shown on Schedule IV-F-2.

ONTARIO HYDRO
COMPUTATION OF MARGINAL UNIT COST
DEMAND-RELATED

		Production	Transmission
		-----(1975 Dollars per Kw)------	
		(1)	(2)
(1)	Long-Run Unit Investment	\$186.00[1]	\$168.00
(2)	Revenue Requirement Related to Capital Investment	10.61%	10.50%
(3)	Allowance for Property Tax Payments[2]	0.20%	0.20%
(4)	Total (2)+(3)	10.81%	10.70%
(5)	Annualized Costs (4)x(1)	\$ 20.11	\$ 17.98
(6)	Demand-Related Operation and Maintenance Expense	-	\$ 1.20
(7)	Demand-Related Costs (5)+(6)	\$ 20.11	\$ 19.18
(8)	Materials and Supplies (1)x2.0%[3]	\$ 3.72	\$ 3.36
(9)	Demand-Related Cash Working Capital (6)x1/8	-	0.15
(10)	Total Working Capital (8)+(9)	\$ 3.72	\$ 3.51
(11)	Revenue Requirement for Cash Working Capital (10)x10.0%[4]	\$ 0.37	\$ 0.35
(12)	Total Demand-Related Costs (7)+(11)	\$ 20.48	\$ 19.53
(13)	Total Marginal Costs (Rounded)	\$ 20.00	\$ 20.00

[1] Cost of a combustion turbine supplied by Ontario Hydro, converted to 1975 dollars and adjusted for planned reserve margin of 20 percent.
[2] Estimated by NERA on the basis of forecast tax payments and plant in service from data in Ontario Hydro Financial Forecast 1975-1980, Comptrollers Division, 750224.
[3] Based upon analyses undertaken by NERA of the relationship between materials and supplies and gross investment.
[4] Overall cost of capital to Ontario Hydro during the planning period.

Source: Line (1): Col. (2): Schedule IV-B-1.
Line (2): Col. (1): Schedule IV-D-1, Table A.
Col. (2): Schedule IV-D-1, Table B, p. 2.
Line (6): Col. (2): Schedule IV-C-1.

ONTARIO HYDRO
DEVELOPMENT OF CAPACITY COST ALLOCATION FACTORS
BY COSTING PERIOD

Costing Period	Relative Value of LOLP	Hours in Costing Period[1]	LOLP x Hours	LOLPxHours ÷ Σ [LOLPxHours]	Allocation Factor
			(1)x(2)	(3)÷2,084	
	(1)	(2)	(3)	(4)	(5)
Winter (October-March)	0.87	2,083	1,812	0.869	0.87
Base Running (April-September)	0.13	2,091	272	0.131	0.13
Off Peak (Nights and Weekends)	0.00	4,592	-	-	0.00
	1.00	8,766	2,084		

[1] Peak hours are 7 a.m. to 11 p.m., Monday through Friday.

Source: Col. (1): Schedule III-1

ONTARIO HYDRO
COMPUTATION OF MEAN RELATIVE PEAK DEMAND
BY COSTING PERIOD

	Mean Relative Peak Demand[1]
Winter	
October	0.87
November	0.95
December	1.00
January	1.00
February	0.99
March	0.93
Period Average	0.96
Base	
April	0.89
May	0.84
June	0.85
July	0.84
August	0.86
September	0.87
Period Average	0.86

[1] Mean relative peak demands reflect monthly forecast peak demands divided by annual forecast peak demands for the costing years 1976-1977 through 1983-1984.

Source: Based on data supplied by Ontario Hydro.

SCHEDULE IV-F-2

ONTARIO HYDRO
MARGINAL DEMAND-RELATED UNIT COST
BY COSTING PERIOD

Costing Period	Annual Marginal Cost[1] (Dollars per Kw)	Allocation Factor	Mean Relative Peak Demand	Marginal Unit Cost (Dollars per Kw) [(1) x (2)] ÷ (3)
	(1)	(2)	(3)	(4)
Winter		0.87	0.96	
Production	$21.00			$19.03
Transmission	21.00			19.03
Total				$38.06
Summer		0.13	0.86	
Production	$21.00			$ 3.17
Transmission	21.00			3.17
Total				$ 6.34

[1]Annual marginal costs of $20.00 and $20.00 for production and transmission respectively, have been multiplied by 1.05 to account for losses.

Source: Col. (1): Schedule IV-E-1, line (13).
Col. (2): Schedule IV-F-1, p. 1, col. (5).
Col. (3): Schedule IV-F-1, p. 2, col. (1).

V. MARGINAL ENERGY COSTS

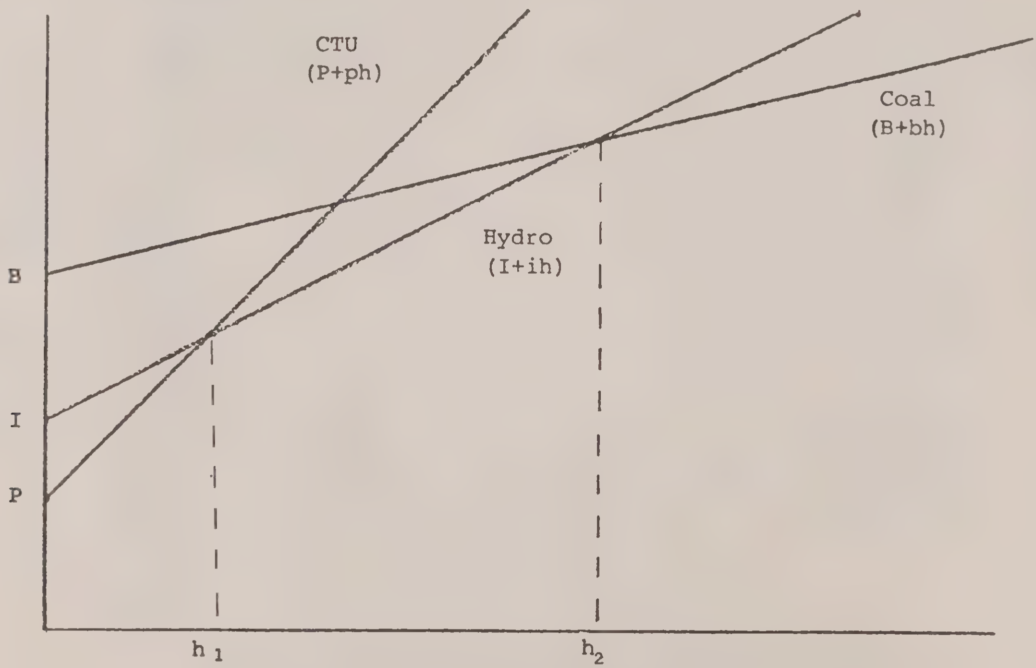
The marginal energy or running costs are the time-differentiated variable costs associated with energy consumption. These costs consist of the fuel and variable operation and maintenance expenses incurred by the generating unit that will provide marginal energy. As previously described, the additional cost to the system of an increase in demand or the savings from a decrease in demand is the running cost of the marginal generating unit.

Marginal running costs were obtained from Ontario Hydro's production cost modelling program, in the form of system incremental costs by seasonal and diurnal periods. The program based system incremental costs on forecast thermal production costs from United States bituminous coal. Implicitly, when peaking hydro facilities are marginal, the energy produced is valued at the cost of coal. However, the manner in which the peaking hydro is used by Ontario Hydro combines both the characteristics of a peaking combustion turbine unit and an intermediate load range coal unit. It therefore follows that replacement of peaking hydro energy would require a combination of CTU and coal units. The value of peaking hydro energy to Ontario is, therefore, somewhere between the running cost of a CTU and a coal unit. To derive the marginal running cost, it is necessary to impute a cost to peaking hydro energy based on its value to Ontario Hydro.

How can this be done? We must assume that, in principle, the aim is to schedule the water to displace as much high-priced fuel as possible, within the limits of the plant's own capacity and water supply. Using the theories explained in the NERA simplified model of the generation system, [1] we construct the diagram below.

The total cost curve for each type of machine starts at its annual fixed cost per kW and rises over hours used by its variable cost per kWh. The least total cost machine for a number of hours is the machine whose total cost curve is closest to the horizontal axis. In this case, B, b, P and p are known. By estimating h1 and h2, we can solve for i, the imputed running cost for hydro. By fitting the energy produced by CTUs and peaking hydro under typical annual load duration curves, it was estimated that h1 was

[1] Streiter and Mahoney, "A Simplified Model of Time-of-Day/Seasonal Pricing," NERA, 1975.



Where:

P,p	are capital and running costs of CTUs,
B,b	are capital and running costs of thermal coal,
I,i	are imputed capital and running costs of hydro and
h_1,h_2	are minimum and maximum number of hours run by hydro.

100 and h2 (the maximum number of hours that peaking hydro operated) was 3,900. The imputed running costs of peaking hydro is 14 mills per kWh. The detailed computations are shown in Appendix V-A. Also included is an analysis demonstrating that the level of the imputed running costs is fairly insensitive to the precise estimate of annual capital costs.

Having imputed a value for the running cost of peaking hydraulic, the next step is to incorporate this cost into a marginal running cost for the various costing periods.

On an annual basis, 47.6 per cent of the hours, or 4,170 hours, are peak hours. Examining a load duration curve, we see that peaking hydro runs for a maximum of about 3,900 hours. Since the peak period lasts 4,170 hours, assuming that, in general, night and weekend hour loads are below weekday peak-hour loads year-round, and having been informed that peaking hydraulic is generally not run during the off-peak hours, we have decided that it would be appropriate to use the marginal running costs originally supplied by Ontario Hydro for the off-peak hours. These costs are shown on Schedule V-1.

The on-peak hours present a more complex problem. Again, examining the load duration curve, a portion of the load duration curve (the first 100 hours) should be costed at 48 mills/kilowatt-hour, the average running cost of a CTU. Examining seasonal load levels, it is clear that these hours are all in the winter. Turning now to the section of the curve represented by peaking hydro, it is necessary to decide whether to price all peaking hydro at the same imputed cost or to price a portion of the load duration curve where hydro most probably displaces CTU energy at a higher cost using an alternative method. As it is our understanding that peaking hydro is operating the year-round to meet the daily movement in load, we do not believe that it would be proper to assign different costs to different parts of the load duration curve for which peaking hydro is marginal. Also, while we feel it is correct to place the first 100 hours of the load duration curve in the winter and the 271 hours of the peak period that are met by thermal coal in the base season, it would require an extensive load analysis to separate the hours on the load duration curve for which peaking hydro is marginal into seasons. The resulting marginal running costs will, therefore, reflect for the winter peak hours a weighted average of CTU and imputed peaking hydro costs, and for the base-running peak hours a weighted average of peaking hydro and intermediate coal running costs.

The winter season peak-hour marginal running cost is 15.90 mills per kilowatt-hour and the base season peak-hour marginal running cost is 13.63 mills per kilowatt-hour. These computations are shown on Schedule V-2.

The off-peak hour marginal running cost is 11.00 mills per kilowatt-hour all year.

ONTARIO HYDRO
CALCULATION OF IMPUTED RUNNING COST FOR PEAKING HYDRAULIC UNITS

Based on the diagrams and the method described in the text, the imputed running cost of peaking hydro is derived below. The costs used in these calculations are 1975 cost data supplied by Ontario Hydro. The capital costs for a peaking CTU and an intermediate coal plant are $155/kilowatt and $300/kilowatt, respectively. The running costs are 48 mills/kilowatt-hour and 11 mills/kilowatt-hour, respectively. We will annualize these costs using the traditional levelized carrying charge method.

The annual costs of capacity are as follows:

CTUs	Intermediate
10.61% x $155/Kw = $16.45/Kw	10.75% x $300/Kw = $32.25/Kw

Returning to the notation introduced in Section V:

Traditional Levelized

$B = \$32.25$

$P = \$16.45$

$b = 11$ mills

$p = 48$ mills

$h_1 = 100$

$h_2 = 3{,}900$

we see that $B-P = (h_2 - h_1)i - h_2 b + h_1 p$. Solving for i under the levelized carrying charge method, we have:

$$32.25 - 16.45 = (3{,}800)i - 3{,}900(0.011) + 100(0.048)$$
$$15.80 = 3{,}800i - 42.9 + 4.8$$
$$53.90 = 3{,}800i$$
$$0.014 = i.$$

In summation, the imputed running cost of peaking hydro facilities is 14 mills/kilowatt-hour.

The following table analyzes the sensitivity of the imputed running cost of peaking hydro to a change in the spread of the annualized capital costs of CTUs and intermediate coal-fired units.

Spread of Capital Costs	Running Cost	Percent in Running Cost
As Assumed	14.00	
-10%	13.77	-1.64
-30%	12.94	-7.57
+10%	14.60	+4.29
+30%	15.43	+10.21

Note: Running costs are expressed in mills per kilowatt-hour.

ONTARIO HYDRO
OFF-PEAK HOUR MARGINAL RUNNING COSTS

Year	Off-Peak Hours: Freshet	Summer	Fall	Winter	Annual Average
	--------------------(Mills/kWh)--------------------				
	(1)	(2)	(3)	(4)	(5)
Marginal Fuel Cost					
1976	10.00	10.02	9.92	10.14	10.02
1977	9.36	10.70	10.60	10.81	10.37
1978	10.45	10.38	10.45	10.51	10.45
1979	9.99	9.86	9.91	9.97	9.94
1980	10.34	10.21	10.09	10.30	10.24
Average Marginal Fuel Cost, 1976-1980	10.03	10.23	10.19	10.35	10.20
Variable O & M Cost[1]	0.60	0.60	0.60	0.60	0.60
Marginal Running Cost	10.63	10.83	10.79	10.95	10.80
Marginal Running Cost Used In Study			11.00		
Adjusted for Marginal Energy Losses[2]			11.66		
Rounded to			12.00		

[1] Estimate of variable O & M costs is based on a survey of the 1974 operation of recently installed coal-fired steam plants and has been adjusted to 1975 dollars

[2] Based upon data supplied by Ontario Hydro, the adjustment factor for marginal energy losses for the off-peak hours has been estimated to be 1.06

Source: Marginal fuel costs were supplied by Ontario Hydro

SCHEDULE V-2

ONTARIO HYDRO
PEAK-HOUR MARGINAL RUNNING COSTS

	Hours of Operation at Margin	Average Height of Load Duration Curve at Margin (Percent of Peak Load)	Weighting Factor: Value	Weighting Factor: Percent	Running Cost --(Mills per kWh)---	Weighted Average Marginal Running Cost --(Mills per kWh)---
	(1)	(2)	(3) (1)x(2)	(4)	(5)	(6)
Winter						
CTUs	100	98%	98	5.82%	48.00[1]	
Peaking Hydro	1,983	80	1,586	94.18	14.00[2]	
Seasonal Peak-Hour Marginal Running Cost						15.98
Adjusted for Marginal Energy Losses[3]						17.10
Rounded to						17.00
Summer						
Peaking Hydro	1,910	74%	1,413	91.87%	14.00[2]	
Intermediate Coal	181	69	125	8.13	11.00[4]	
Seasonal Peak-Hour Marginal Running Cost						13.76
Adjusted for Marginal Energy Losses[3]						14.72
Rounded to						15.00

1 Fuel cost of 44 mills for most efficient CTU unit as supplied by Ontario Hydro plus 4 mills for variable operation and maintenance expenses exclusive of fuel based on a survey of work done by NERA

2 Appendix V-A

3 Based upon data supplied by Ontario Hydro, the adjustment factor for marginal energy losses for the peak hours has been estimated to be 1.07

4 Based on fuel cost supplied by Ontario Hydro and NERA estimate of variable operation and maintenance expenses

Source: Based on data supplied by Ontario Hydro

A simplified model of time-of-day/seasonal pricing

by

Sally Hunt Streiter

and

Leo T. Mahoney, Jr.

The theory of marginal cost pricing posits that the price charged for electricity at any time should equal the cost of providing a small amount more, or the savings from providing a small amount less. Since in a complex system with a cyclical demand there are different costs at different times, we have to find a way to estimate the different costs. Fortunately, the engineers got there before the economists and produced a variable technology adapted to the variable demand. The technology permits different equipment to serve demands of different durations, and by simulating the planning process by which equipment is chosen, it is possible to derive the conditions for a minimum cost system. If the marginal cost principle of pricing is then applied to this simplified system, we can test various hypotheses about the relation of revenues to costs under marginal cost pricing; we can examine the fairness of charges to consumers with different load patterns; we can show how different load patterns vary in cost and how growth affects cost.

The following theorem and corollaries show in a very simplified and schematic way how a kilowatt-hour pricing scheme based on marginal costs for each hour of the year will:

1. Cover total costs, in fact, exactly equate revenues with costs.
2. Be equitable to particular types of consumers.

The proposed pricing rule is that the price to be charged for each kilowatt produced in a given hour of the year should be the hourly running cost of the last machine on line at that point, *plus* an amount equal to the annual cost of one kilowatt of peaking capacity, charged for the peak hour only. (To be a little more realistic, since the exact hour of the peak is unknown, the annual capital cost of the next kilowatt is spread over all the hours when the peak is equally likely to occur.)

The theorem is proven for a schematically simple but representative system containing three plants. This system is assumed to have been designed to minimize the cost of meeting an exogenously determined load curve. This assumption is important, since it gives the conditions under which the pricing rule produces revenues which exactly cover the capital and running costs of the system. All the proofs in this paper refer to this optimal system.

We are entirely aware that the real world has systems which are less than optimal, and that this simplified model can only be of limited application. Nor will marginal costs exactly equate with total costs when technical progress, inflation and other factors are introduced. Nonetheless, it has proved helpful in analyzing non-optimality also, and is presented as a conceptual tool.

THEOREM

Rule

In an optimally planned system prices should be set equal to the marginal running cost at any given hour plus the capital cost of meeting 1 extra Kw of peak demand charged at the peak hour only.

Result

The revenues so obtained will exactly equal the annual capital costs plus the annual running costs of the system.

Proof

Let the following symbols be used in a system with 3 plant types available.

	Annual Capital Cost $/Kw	Running Costs $/Kwh	Hours/ Year Running Time	Kw Capacity
Peaking Plant	X	x	a	A
Cycling Plant	Y	y	a + b	B
Baseload Plant	Z	z	a + b + c	C

Total running time $t = a + b + c = 8{,}760$ hours

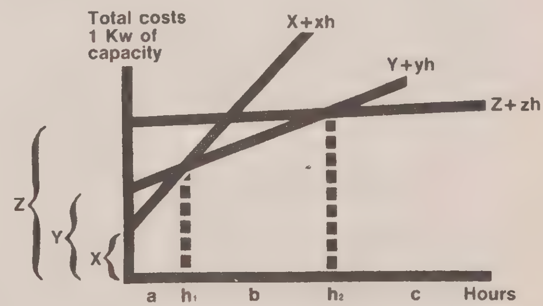
Total capacity $K = A + B + C$

If X, Y, Z, x, y, z are given, it can be shown that in an optimally planned system, the prices below will give the required revenues.

Peak hours: a hours at $(x + X/a)$ $/Kwh
Middle hours: b hours at y $/Kwh
Low hours: c hours at z $/Kwh

This is true whatever the values of A, B and C.

1. Conditions for an optimal system



Use peaking plants when
$X + xh < Y + yh$
Since X, Y, x, y are known
$h_1 = \frac{Y-X}{x-y} = a \ldots\ldots 1)$

Then A is determined by the load curve and the value of a.

Similarly, use cycling plants when
$Y + yh < Z + zh$
$h_2 = \frac{Z-Y}{y-z} = a + b \ldots\ldots 2)$

Then B is determined by the load curve and the value of (a+b)

2. If plant has been optimized, and price has been set according to rules set out above, revenues will equal total annual capital + running costs

Revenues

Period in Which Marginal Machine is:	Plant in Use	Output	Price	Revenues
Peaking Unit	A + B + C	(A + B + C)a	x + X a	$(A+B+C)a\left(x+\frac{X}{a}\right)$
Cycling Unit	B + C	(B + C)b	y	(B + C)by
Baseload Unit	C	Cc	z	Ccz
				Σ Revenues

Costs

Costs	Annual Capital Cost $	Hours in Use	Kwh Generated	Running Cost per Kwh	Total Running Cost
Peaking plant	AX	a	Aa	x	Aax
Cycling plant	BY	a + b	B(a + b)	y	B(a + b)y
Baseload plant	CZ	a + b + c	C(a + b + c)	z	C(a + b + c)z
	Σ Capital				Σ Running

Z Revenues = Z Running + Z Capital

$$(A+B+C)a(x+X\ a)+(B+C)by+Ccz = Aax+B(a+b)y-C(a+b+c)z+AX+BY+CZ$$
$$BX-CX+Bax+Cax+Cby = BY+CZ+Bay+Caz-Cbz \quad 3)$$

In 1) above $\frac{Y-X}{x-y}=a$

then $X=Y-a(x-y)$ ...4)

In 2) above $\frac{Z-Y}{y-z}=a+b$

then $Z=(a+b)(y-z)+Y$ ...5)

Substituting from 4) and 5) into 3)

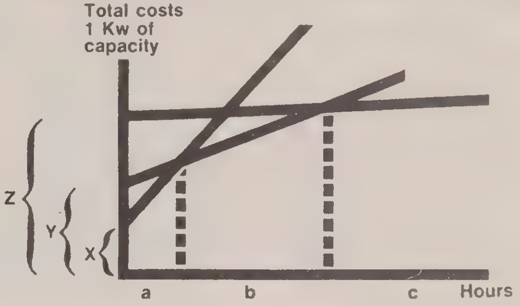
$$(B+C)(Y-a[x-y])+Bax-Cax+Cby = BY+CY+C(a+b)(y-z)+Bay+Caz+Cbz$$

Rearranging and cancelling common terms

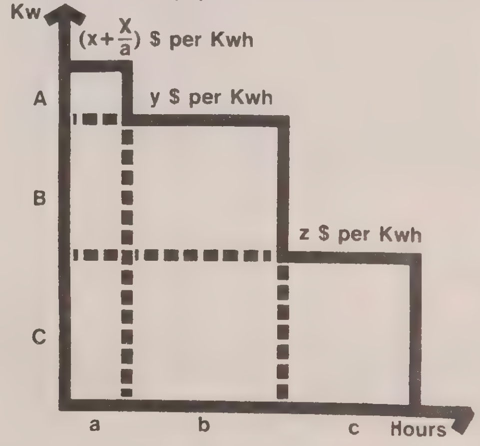
$$BY+CY+Bay+Cay+Cby = BY+CY+Cay+Cby+Bay$$

QED

Relative costs determine optimal running hours and price



Load curve and hours of use determine quantities of equipment and revenue



Note:

1. The result is independent of the magnitude of A, B and C and of their total. The Kw capacity of each type of machine depends only on the load curve
2. The optimal hours of running each class of machine

depend only on the relative costs.

3. The assignment of capital costs to the hours when the peaking machine is used, and equally over those hours, is arbitrary.

The rule more rigorously defined is that each kilowatt hour should be charged (the probability of failure) × (the cost of the next Kw to meet the failure)

This may mean spreading the capital cost of the Kw over more hours of the year, or fewer. However, if peaking charges cover too few hours a new peak may pop up.

Corollary A

A user who has a flat load curve and used M Kwh/hour continuously throughout the year will be paying exactly his fair share

For if his demand had been met by addition of a baseload plant with M Kw capacity

Fair Share Cost $= MZ + M(a+b+c)z$

Actual Charges $= M(a[x + X/a] + by + cz)$

This is fair if

$MZ + Maz + Mbz + Mcz = Max + Mby + Mcz + MX \quad \ldots 6)$

In 1) above $\dfrac{Y-X}{x-y} = a$

In 2) above $\dfrac{Z-Y}{y-z} = a+b$

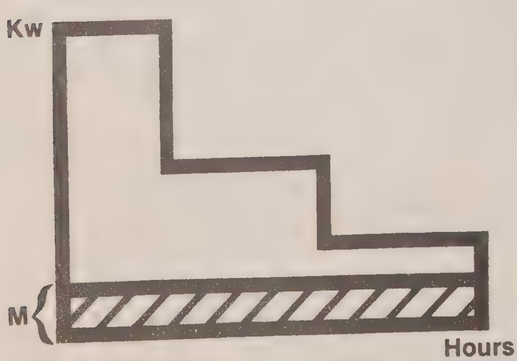
Adding 1) + 2) $Z-X = ax + by - az - bz \quad \ldots 7)$

Substituting in 6) from 7)

$MZ + Maz + Mbz + Mcz = Max + Mby + Mcz + M(Z - ax - by + az + bz)$

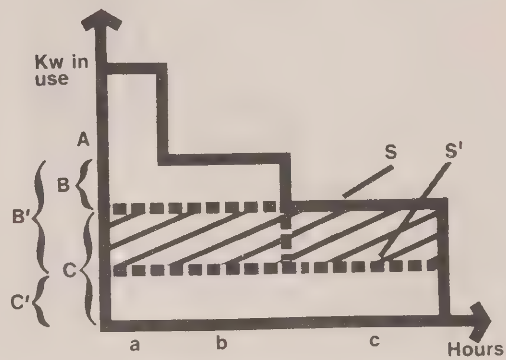
Cancelling common terms

$MZ + Maz + Mbz + Mcz = MZ + Maz + Mbz + Mcz$ QED



Corollary B

If two firms differ only in their load curve characteristics, with the difference only in the bottom of the load curve, it can be shown that the same pricing rule yields each firm sufficient to cover its costs.



S has more baseload need than S′, and consequently installs C Kw of baseload and B Kw of intermediate plant, where S′ installs C′ and B′ respectively.

The difference in capital and running costs between the systems will equal the difference in revenue under the pricing system.

For the shaded rectangle

Costs S–S′ = difference in capital costs + difference in running costs

$= (C-C')Z + (B-B')Y + (C-C')z(a+b+c) + (B-B')y(a+b) \quad \ldots 8)$

Revenues S–S′ $= (C-C')cz$

Since $C-C' = -(B-B')$

and $Z-Y = (y-z)(a+b)$ from 1)

In 8) Costs S–S $= (C-C')[Z-Y+az+bz+cz-ay-by]$

$= (C-C')[(a+b)(y-z)+az+bz+cz-ay-by]$

$= (C-C')cz$

= Revenues S–S′ QED

Corollary C

The fuel savings from the baseload and cycling plant offset part of the capital cost of the plant so that the net cost per Kw is equal to the cost of the peaking plant.

In other words

Capital cost of peaking plant
= Capital cost of cycling plant *less* fuel savings from running the cycler rather than the peaker.
= Capital cost of baseload plant *less* fuel savings from running baseload rather than the cycler and the peaker.

Proof

In 1) $\frac{Y-X}{x-y} = a$

$X = Y-a(x-y)$ QED

In 2) $\frac{Z-Y}{y-z} = a+b$

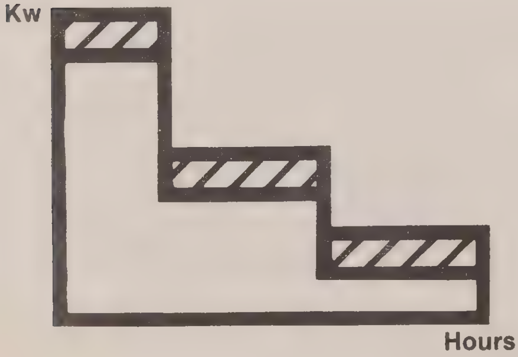
Adding 1) + 2)

$X = Z-a(x-z)-b(y-z)$ QED

Corollary D

As a system grows, if its configuration is optimal at the beginning and end of the growth, the revenues from the growth will equal the cost of the growth. This is true for even or uneven growth.

1) For *even* growth of G Kw in each period



System before growth		System after growth
Peaking plant	A Kw	A Kw
Cycling plant	B Kw	B Kw
Baseload plant	C Kw	C + G Kw

Cost of growth = $G(Z + [a+b+c]z)$

Revenues from growth = $G(a[x + \frac{X}{a}] + by + cz)$

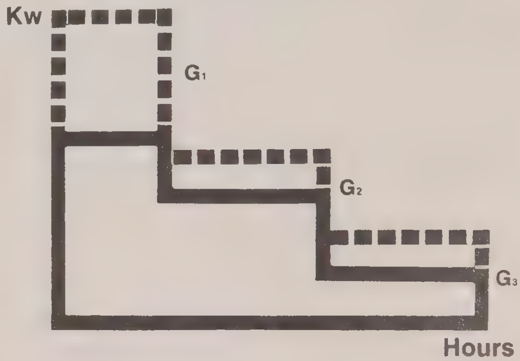
These are equal if

$G(Z + [a+b+c]z) = G(ax + by + cz + X)$ ...9)

from 7) $Z-X = by-az-bz + ax$

Substituting in 9) $G(Z + [a+b+c]z) = G(Z + ax + bz + cz)$

2) For *uneven* growth of G_1, G_2, G_3 at peak, intermediate period and off-peak



System before growth		System after growth
Peaking	A	$A + G_1 - G_2$
Cycling	B	$B + G_2 - G_3$
Baseload	C	$C + G_3$
Total Kw	A + B + C	$A + B + C + G$

Cost of net growth in peaking capacity = $(G_1 - G_2)[X + ax]$
Cost of net growth in cycling capacity = $(G_2 - G_3)[Y + (a+b)y]$
Cost of net growth in baseload capacity = $G_3(Z + [a+b+c]z)$

Revenues from net growth = $G_1 a(x + \frac{X}{a}) + G_2 by + G_3 cz$

Costs equal revenues if

$$(G_1 - G_2)(X + ax) + (G_2 - G_3)(Y + [a+b]y) + G_3(Z + [a+b+c]z)$$
$$= G_1 a(x + \frac{X}{a}) + G_2 by + G_3 cz$$

$$G_1(X + ax) + G_2[Y + (a+b)y-X-ax] + G_3[Z + (a+b+c)z-Y-(a+b)y]$$
$$= G_1 a(x + \frac{X}{a}) + G_2 by + G_3 cz$$

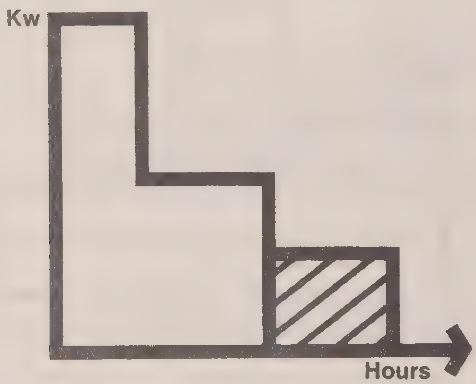
Since $Y-X = a(x-y)$
$Z-Y = (y-z)(a+b)$

$G_1(X + ax) + G_2 by + G_3 cz = G_1 a(x + \frac{X}{a}) + G_2 by + G_3 cz$ QED

This means that the cost of growth in *each period* and *in total* are equal to the running costs in each hour plus the cost of the peaking plant.

Corollary E

A consumer who uses only off-peak power should not be charged any capital costs, only the running cost.



If the off-peak consumer did not exist then the system configuration would be different. The net total cost to the system of the changed configuration is equal to the running cost in the off-peak hours, or Ccz

Proof

If the consumer had not existed. system would have been

A Kw peaking
(B + C) Kw cycling
0 baseload

Cost without him $= AX + (B + C)Y + Aax + (B + C)(a + b)y$

If the consumer now exists, *and the system is reoptimized*

Cost with him $= AX + BY + CZ + Aax + B(a + b)y + C(a + b + c)z$

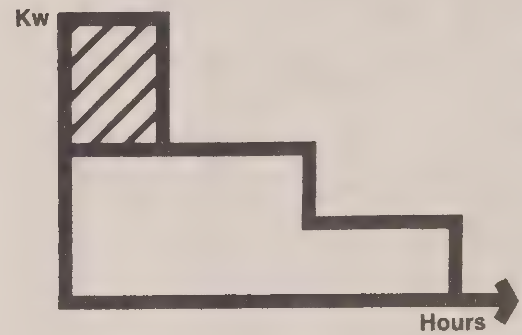
Difference in costs with him and without him

$$\begin{aligned}
&= CZ - CY + C(a + b + c)z - C(a + b)y \\
&= CZ - CY + C(az + bz + cz - ay - by) \\
&= CZ - CY - C[(a + b)(y - z) + cz] \\
&= C(Z - Y - Z + Y) + Ccz \\
&= Ccz
\end{aligned}$$

This is what we ask him to pay.

Corollary F

But what if the consumer requires all his power at the peak? Then charging him the capital costs covers the incremental cost to the system.



$$\begin{aligned}
\text{System without him} &= B + C \\
\text{System with him} &= A + B + C \\
\text{System costs without him} &= BY + CZ + B(a + b)y + C(a + b + c)z \\
\text{System costs with him} &= AX + BY + CZ + Aax + B(a + b)y + C(a + b + c)z \\
\text{Difference in system costs} &= AX + Aax \\
&= Aa(x + X/a)
\end{aligned}$$

This is what we ask him to pay.

ILLUSTRATION

ILLUSTRATIVE EXAMPLE TO DEMONSTRATE THAT BY CHARGING THE CAPITAL COST OF PEAKING CAPACITY DURING PEAK HOURS, THE RUNNING COST OF PEAKING CAPACITY DURING PEAK HOURS AND THE RUNNING COST OF THE MARGINAL MACHINE AT OTHER TIMES, THE TOTAL COSTS OF AN OPTIMIZED SYSTEM WILL BE RECOVERED.

ASSUME:

1) A system whose load duration profile permits each type of production plant to operate the optimum number of hours [The optimum number of running hours for any plant is that number of running hours beyond which some other type of plant would operate at a lesser total cost].

2) The following symbols are used

	Peak-ing	Inter.	Base-load
Capital $/Kw	P	I	B
Annual charge %	AC_P	AC	AC_B
Running costs $/Kwh	p	i	b
Hours of running time	h_1	h_2	h_3
System configuration (Kw)	K_1	K_2	K_3

3) In this example the following values, approximating those of an actual utility, are taken

	Peak-ing	Inter.	Base-load
Capital $/Kw	140	300	500
Annual charge %	20%	15%	15%
Running costs $/Kwh	.03	.015	.004
System configuration (1 Kw System)	.2	.3	.5

A. COMPUTATION OF OPTIMUM RUNNING HOURS:

1) PEAKING CAPACITY

$$\$P(AC_P) + \$p(h_1) = \$I(AC_I) + \$i(h_1)$$

Solve for h_1–

$$\$p(h_1) - \$i(h_1) = \$I(AC_I) - \$P(AC_P)$$

$$h_1 = \frac{\$I(AC_I) - \$P(AC_P)}{\$p - \$i}$$

Substitute the assumed costs

$$h_1 = \frac{\$300(.15) - \$140(.20)}{\$.03 - \$.015}$$

$$= \frac{\$45 - \$28}{\$.015} = \frac{17}{.015} = 1133 \text{ hrs.}$$

2) INTERMEDIATE CAPACITY

$$\$I(AC_I) + \$i(h_2) = \$B(AC_B) + \$b(h_2)$$

Solve for h_2–

$$\$i(h_2) - \$b(h_2) = \$B(AC_B) - \$I(AC_I)$$

$$h_2 = \frac{\$B(AC_B) - \$I(AC_I)}{\$i - \$b}$$

Substitute the assumed costs–

$$h = \frac{\$500(.15) - \$300(.15)}{\$.015 - \$.004}$$

$$h_2 = \frac{\$75 - \$45}{\$.011} = \frac{30}{.011} = 2727 \text{ hrs.}$$

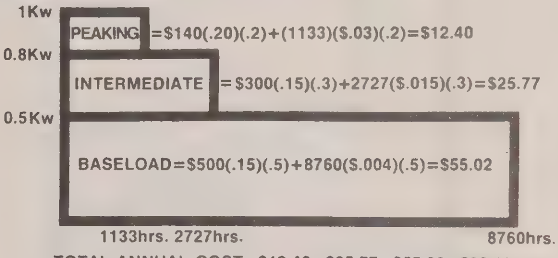
3) BASELOAD CAPACITY

Baseload running hours = 8,760 hrs.

B. REVENUES ARE RECOVERED

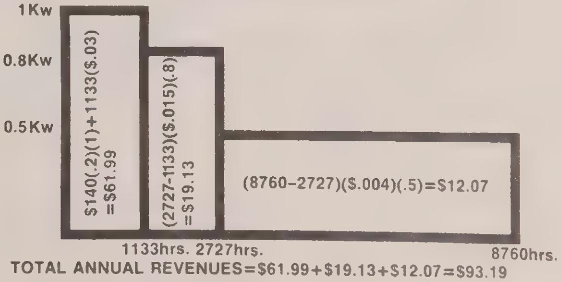
With prices set equal to running costs of the marginal machine [3¢, 1.5¢, 0.4¢ per Kwh] in each period, plus a capital component equal to the cost of 1 Kw of peaking capacity, the total costs are recovered.

COMPUTE TOTAL ANNUAL COST:



TOTAL ANNUAL COST=$12.40+$25.77+$55.02=$93.19

COMPUTE TOTAL ANNUAL REVENUES:



TOTAL ANNUAL REVENUES=$61.99+$19.13+$12.07=$93.19

C. A 100-PERCENT LOAD FACTOR CUSTOMER IS FAIRLY CHARGED

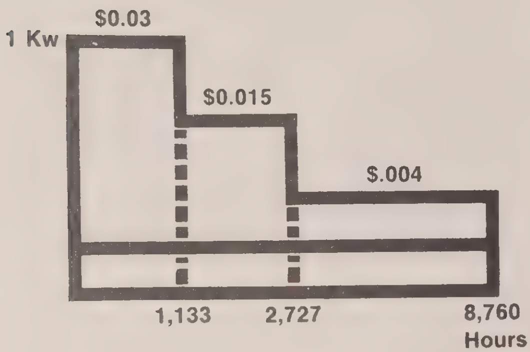
Using the values in the Illustration, we show the 100 percent load factor customer pays his fair share under marginal cost pricing

If the 100 percent load factor consumer were added, the system would need to add a baseload unit at a cost of.
$500 (.15) + 8,760(.004) = $110 per year

Under marginal cost pricing he would pay

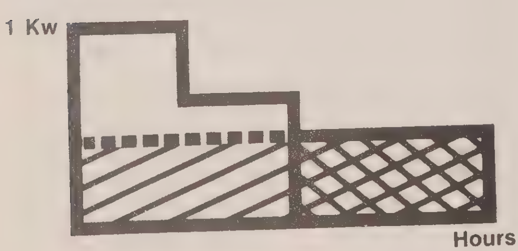
$28 (spread over the peaking hours)
+ $0.03 × 1,133 (peak running time)
+ $0.015 × (2,727–1,133) (intermediate running time)
+ $0.004 × (8,760–2,727) (off-peak running time)
= $110 per year

This can be shown to be true for all optimal systems



D. THE OFF-PEAK CONSUMER PAYS ONLY THE RUNNING COSTS

If the off-peak consumer did not exist, the system would have more intermediate capacity and less baseload capacity. The off-peak consumer causes a replacement of intermediate capacity with baseload capacity, which has a higher capital cost and a lower operating cost. This is the only difference to system costs.



Taking costs for shaded area only

Total cost of plant optimized with off-peak consumer
= $500(.15) + 8,760(.004) = $110

Total cost of plant optimized without off-peak consumer
= $300(.15) + 2,727(.015) = $85.9

Difference = $24.1

Off-peak charges proposed for off-peak consumer
= $.004 × 6,033
= $24.1

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APPENDIX 2: The Assignment of Marginal Capacity Costs to Costing Periods Based on Loss of Load Probabilities: An Elaboration

Depending on the particular system under study, we can get various amounts of information about the probability that the load at any particular time will exceed the level of available capacity. These estimates reflect information on the probability distribution of demands over the year, maintenance schedules, and forced-outage rates. In making use of these probability estimates, we recognize the general principle that the price at any period of time should reflect the expected marginal cost of energy plus the expected marginal shortage cost.[1]

Following the approach used by the French, we also recognize that under several simplifying assumptions, the expected marginal cost can be expressed in terms of the marginal cost of capacity to all periods which have a significant shortage probability, in accordance with the relative probabilities in the different rating-periods.

Briefly, the argument goes as follows. Assume that we can summarize the uncertainty in demand, forced outages, and maintenance requirements associated with each hour (i) of the year by a probability distribution, which for any level of capacity gives us a probability P_i that demand will exceed available capacity in each hour. Other things being equal, the larger the amount of capacity we build, the lower will be the probabilities of shortage. Let us assume that the marginal cost of not being able to supply a kilowatt of demand because of capacity constraints is given by d dollars in each period (allowing the d's to vary across periods does not change the nature of the results), and the marginal capacity cost is given by C dollars per kilowatt. Efficiency requires us to expand capacity until the marginal cost of capacity equals the marginal benefit of adding that capacity, which in turn is given by the expected marginal shortage cost summed over all hours of the year. This condition is given by $\Sigma P_i d = C$ (Formula 1).

Now consider the decision to use an extra kilowatt-hour during any hour. With probability P_i, there will not be enough capacity to provide the service, so that the expected shortage costs associated with this decision are $P_i d$ (Formula 2).

But Formula 1 tells use that if the system has been expanded efficiently, then $d = C/\Sigma P_i$ (Formula 3), and Formula 2 can be written as $P_i d = (P_i/\Sigma P_i).C$; which gives the expected shortage cost associated with the decision to use one kilowatt-hour more (or less) during each hour. Our first reaction, therefore, is to set the rate (R_i) during each period to equal the expected marginal energy cost (a_i) plus the expected marginal shortage cost given by Formula 4: that is to say $R_i = a_i + (P_i/\Sigma P_i).C$ (Formula 5), and $\Sigma R_i = \Sigma a_i + C$ which is equivalent to the result for the sum of the prices for the simple deterministic model discussed in the previous sections.

However, we are not quite finished. Referring back to the optimal expansion relationship (Formula 1), we realize that associated with this condition is some level of reserve margin (r) measured by the difference between peak capacity and expected (mean) demand. The larger the variance of the probability distribution (other things being equal), the larger the reserve margin will be. The cost of this reserve margin does not yet appear anywhere in the rates. This is because the question we asked was, What is the cost of consuming one more or one less kilowatt-hour in each period with certainty (or alternatively, without any variance component)? If we had asked instead, What is the cost of adding a one-kilowatt reproduction of the existing demand configuration with identical stochastic characteristics so as to maintain the same level of system risk?, then we should have to include a reserve margin, and the marginal cost would be $(l+r)C$ dollars.

We have accounted for the variance in load, and the associated reserve margin, by including the reserve margin in $R_i = a_i + (P_i/\Sigma P_i)(l+r)C$ (Formula 7), and $\Sigma R_i = \Sigma a_i + (l+r)C$ (Formula 8).

Note at this point that rates during all periods make some contribution to the total capacity costs of the system, both because the marginal energy costs (a_i) are generally higher than the average energy costs during any hour, and because of the allocation of the marginal costs of capacity using the loss-of-load probabilities. These relationships may also give us a basis to charge differential rates to customers who do not wish to pay for the level of reliability the system has been designed for (perhaps by opting for interruptible rates), although we have not as yet explored this possibility in any detail.

One final simplification must be mentioned in conclusion. We are not proposing to set different rates for every hour of the year. In addition, the probability distribution of load losses is similar for a small number of groups of hours. We have therefore chosen to isolate three or four homogeneous groups of hours, each containing h_i hours, which have the same loss-of-load probabilities for any level of system capacity. Therefore, for computation purposes, $(P_i h_i/\Sigma P_i h_i)(l+r)C$ is the share of marginal capacity costs chargeable to the hours h_i, where h_i is the number of hours in each rating-period and P_i is the associated loss-of-load probability.

[1]See M.A. Crew and P.R. Kleindorfer, "Peak Load Pricing With A Diverse Technology" and P.L. Joskow, "Contributions to the Theory of Marginal Cost Pricing", *Bell Journal of Economics and Management Science*, Spring 1976

APPENDIX 3: Marginal Costing Study Data Sources

Data used in the determination of the long-run marginal costs of Ontario Hydro were supplied by Ontario Hydro personnel. When the study was commissioned, it was agreed that part of NERA's responsibility would be to prepare requests for whatever data would be necessary for use in the determination of long-run marginal costs. These requests were passed through the Ontario Hydro costing study group to the sections best suited to provide the necessary information. NERA personnel met with Ontario Hydro personnel to clarify the requests and Ontario Hydro's responses.

The nature of the data needed for a study of long-run marginal costs and the ongoing evolution of the marginal costing methodology are such that data are sometimes not available within the time frame or budget of the study. Data are often not available in the best possible form. Often information must be processed to be useful in the study and this requires even more information. Contingent upon developments in the methodology, additional data requests are made.

Peak load forecasts, budgeted capital and operation and maintenance expenses, forecast fuel expense and forecast system dispatch are examples of the type of information necessary to compute marginal costs levels. Loss-of-load probabilities and daily load curves are information that is essential in choosing costing periods. Electric losses at time of peak and under different load conditions are necessary to adjust demand costs, to allow for losses at time of peak, and to adjust energy costs, to allow for incremental energy losses.

The only possible source for information of this type is the people who are constantly involved in the planning and operation of the electric system. Long-run marginal costs, it must be remembered, are not tied to cash flows over any particular time period. Instead, given a level of technology and a constant price level (recognizing relative price changes among inputs to an electric system), the long-run marginal costs attempt to measure, in constant dollars, the cost level of consumption on a time-differentiated basis. To do this properly, there is no formula. The analyst must define his goal and through discussion with operating and planning people determine what data are appropriate to the computations.

In Appendix 4, we have offered recommendations for improvements in the accounting and data compilation and storage systems that would facilitate a marginal cost study. Eventually, as the marginal costing methodology for electric services matures, it will be possible to develop standardized forms of data reporting that will render marginal cost analyses more thorough and efficient. Attached to this appendix is a copy of the basic data request given to Ontario Hydro.

APPENDIX 3A: Data Required by NERA

1. Summer and winter peak load forecasts for the next ten years and actual peak loads for the past 20 years. Summer and winter peak day load curves for the past five years along with monthly cooling and heating degree days for the same period. In this regard, we need to know the relationship between weather for the period and "normal" weather. (A write-up explaining your peak normalization procedures including design-day conditions would be helpful.)
2. Hourly, marginal energy costs for the next five to ten years. If these are not available, a month-by-month system dispatch showing the amount of hours each unit will be run, the energy generated by each plant, the MBTU consumed by each plant, the cost of fuel per MBTU in base-year dollars (general inflation excluded), and the base-year dollar cost per kilowatt-hour of variable O&M expenses, by plant. A description of any operating conditions that significantly alter dispatch from being done on a "merit order" basis.
3. Monthly load duration curves expected to be typical of the planning period.
4. For each month, the monthly peak day, typical weekday, typical Saturday and typical Sunday load curves plotted as a per cent of annual peak load. If there are no reasons to expect that these curves will change relative to the peak load, one set for the period will suffice.
5. Loss-of-load probabilities for each hour for the next five to ten years. If these are not available, loss-of-load probabilities by month for day (peak) and night (off-peak) for the next five to ten years.
6. Planned production capacity additions for the next five to ten years, timing of units and dollars per installed kilowatt of capacity in present day dollars. What method does your company use in estimating cost of facilities and removing inflation?
7. What is your planned capacity reserve margin over the next five to ten years? What method of generation planning is employed by the company, e.g., yearly loss-of-load probability?
8. Estimate of operation and maintenance expense and fuel cost for all existing and future generation by type of fuel and type of plant.
9. Long-range, five to ten year budgeted annual expenditures for transmission investment in present day dollars. Please indicate, if possible, any dollars budgeted for replacement of retired plant and any unusual projects taking place during this period.
10. Long-range, five-to-ten year budgeted annual expenditures for distribution investment in present day dollars. Please indicate, if possible, any dollars budgeted for replacement and/or reliability.
11. Estimate the cost of adding a new overhead and underground residential, commercial and industrial customer based on present minimum engineering standards. Estimate the cost of modifying aforementioned standards for electric heat. Who pays for the additional cost of underground service?
12. A tabulation of capital expenditures over the last 20 years related to transmission and distribution plant broken down by subaccount and by voltage level. Also, indicate whether there were any unusual expenditures during this period such as those related to a new airport or hurricane damage.

12. Tabulation of all operation and maintenance expenses for the last five years. These expenses should be segregated by major function, i.e., generation and transmission, and segregated into subaccounts such as fuel, maintenance of boiler plant, etc.

14. A list of all existing generators, their capacity and fuel type.

15. For the last 20 years, an analysis of the contribution to peak of customers by class and voltage level. Also, the average and year-end number of customers by customer class, served from each voltage level.

16. The capital structure that the company will use to finance projects undertaken during the planning period. The cost of capital the company expects to face during the planning period. A description of any accounting practices related to computing revenue requirements for ratemaking purposes (i.e., use of reserves for rate stabilization, etc.).

17. The type of Iowa Survivor Curve that the company will use to estimate the dispersion pattern of the types of planned investments. The service life that the company will use for straight line depreciation of planned investments, by type of investment (i.e., transmission, distribution and generation by type of fuel). If these data are unavailable for planned investments, supply information on the type of curve currently used and the corresponding service life, by type of investment.

18. A detailed description of what comprises the rate base.

19. A description of all taxes or payments in lieu of taxes paid to the federal, provincial or local governments.

20. Summary of monthly sales and customers, by rate schedule, for the most recent 12-month period.

21. A description of any specific load research work that the company has performed.

22. An analysis of losses by voltage level for demand and energy.

23. Analysis (from bill frequencies) of hours or use of measured demand for rates with demand meters.

24. Analysis (from bill frequencies) of number of bills and consumption by blocks of kilowatt-hour consumption by month for a 12-month period.

25. A map of the system showing existing and proposed generator sites and transmission lines and any general background information such as one would find in a private company's annual report.

APPENDIX 4: Recommendations for Improving Data Inputs to the Marginal Costing Study

In Appendix 2, it was stated that marginal costing methodology is still developing and improvements are necessary in data availability. Herewith are recommendations of the type of data that we feel Ontario Hydro should give thought to compiling and storing.

Costing period selection and capacity cost allocation are currently based on loss-of-load probabilities and daily load curves. Loss-of-load probabilities are, however, only representative of load exceeding generating capability. For the purpose of allocating transmission demand-related costs to costing periods, a measure of the probability that load will exceed the capability of the transmission lines and stations should be developed. Daily costing periods have been selected to encompass 16 hours a day. At this time, we feel that this is necessary to protect against the creation of new peaks. However, if marginal cost based rates are implemented, the responsiveness of consumers to price changes should be sampled and the results used in determining daily peak and off-peak periods in a more scientific manner.

Marginal running costs have been calculated using a thermal production cost modelling program forecast and imputing a cost to hydraulic energy based on the number of hours that this energy was used during the year. More precise marginal running costs could be obtained by incorporating peaking hydro energy (costed at the value of fuel that would be displaced if Ontario Hydro did not have the peaking hydro energy available) into the production cost program.

Transmission investment has been analyzed per added kilowatt of system peak demand. Historic data were not used because of problems with clearing investments to functional subaccounts and the absence of a construction cost index suitable to Ontario Hydro that could be used to convert past investment to constant dollars. In the past, no particular emphasis was placed on developing an accounting system that promptly cleared investments to functional subaccounts and no emphasis was placed on tracking trends in construction costs by these subaccounts. We would recommend that such procedures be undertaken. They would provide the capability to analyze historic marginal investment levels and to analyze further the variability of transmission investment with demand.

We would also suggest that, if possible, transmission budgeting should be compiled on a functional subaccount basis. Costs above those which are necessary to serve current loads, but are being incurred in anticipation of conversion to a higher voltage level, should be isolated. This would further aid in analyzing the variability of transmission investment with respect to increases in demand. Ontario Hydro currently has a policy of pooling costs among voltage levels. If this were to be changed, it would be important to develop investment and peak load data by voltage level.

There is also work to do on computing incremental energy loss factors and loss factors at times other than system peak. Additionally, if the pooling concept is abandoned, this work would involve analyses for the different voltage levels. While this would be difficult on a system as widespread as Ontario, with differences in seasonal and daily location of available capacity, it would lend further precision to the marginal costing study.

INFORMATION REQUIREMENTS FOR ELECTRICITY COSTING

MARGINAL COST STUDY - BULK-POWER SYSTEM
(Allocated data to be in constant dollars)

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
1.	Ten-year load forecast for total system	(i) Determination of changes in load	Power Market Analysis	Produced annually
2.	System incremental running costs (fuel only) by season, day, night, for five years (coal-fired station at this time)	(i) Determination of marginal energy costs	Power Systems Operations	Existing programs must be manipulated to provide this data
3.	Average running costs (including maintenance) for CTU's	(i) Determination of inputed cost of peaking hydraulic	Power Systems Operations	Available
4.	Incremental maintenance costs (including overheads) for Item 2, for five years	(i) Determination of marginal energy costs and inputed cost of peaking hydraulic	Power Systems Operations	Existing programs must be manipulated to provide this data
5.	Projected fuel prices coal, CTU, oil	(i) Determination of inputed cost of peaking hydraulic	Supply Division - Fuels	Available

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
6.	Economic indices	(i) General use	Office of the Chief Economist	Available
7.	Monthly loss of load probabilities for ten years	(i) Determination of costing periods (ii) Determination of capacity cost allocation factors	System Planning	Program available
8.	Loss of load probabilities for ten years (days vs nights)	(i) Determination of costing periods	System Planning	Not produced
9.	Capital costs of capacity additions for ten years	(i) Determination of marginal demand costs	Generation Concepts	Available
10.	Capital costs of CTU's	(i) Determination of marginal demand costs	Generation Concepts	Available
11.	Forecasted O & M costs by voltage level (including overheads) for stations and lines in the bulk power system for five years (115 kV, 230 kV, 550 kV)	(i) Determination of marginal demand costs	Financial Forecasts	Provided in the allocation detail supporting the Financial Forecast
12.	Forecasted capital expenditures in transmission facilities in the bulk power system for five years (115 kV, 230 kV, 550 kV)	(i) Determination of marginal demand costs	Stations, Transmission and Distribution Division	Not available from S T & D but requirements can be met by Financial Forecast

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
13.	Annual carrying charge factors for CTU's, coal-fired stations (or type of station used in Item 2) and Transmission Plants	(i) Determination of marginal demand costs	Unknown, requires an analysis of Iowa Curves and cost of capital	Not computed internally
14.	Forecasted cost of taxes and grants in lieu of taxes	(i) Determination of marginal demand costs	(Require working papers from NERA before identifying source of availability)	
15.	Cost of materials and supplies to the operation of production and transmission facilities	(i) Determination of marginal demand costs	(This measure was based on an analysis done by NERA)	

PART 2: Marginal Costs for the Distribution System

I. INTRODUCTION

Certain of Ontario Hydro's costs are considered to be incurred for the benefit of all customers while others are for certain customers or classes of customer. The first category comprises the costs of the bulk-power system, and is often referred to as common-function costs. The second refers to the costs of the distribution system, or non-common-function costs.

The NERA study determined the marginal costs of the bulk-power system. The objective of this analysis is to determine the marginal costs of non-common functions.

Non-common facilities are those Ontario Hydro provides to supply power at voltage levels below bulk-power levels. Providing electrical service at sub-transmission levels requires transforming the power, distributing it, and metering it. This entails expenses for capital additions as well as for operating, maintenance and administration.

For purposes of cost allocation, the dividing-point between the bulk-power and distribution systems is considered to be the 'high side' of those stations stepping power down to voltage levels below 115 kV. The costs of non-common facilities are currently recorded and/or allocated in the present cost-of-power system. These costs, supplemented by information recorded in the corporate accounting-system, constituted the primary data for analysing marginal non-common function costs.

II. SCOPE

A separate study was conducted on determining and allocating fully distributed non-common costs, and the resulting report is presented as part of the Allocation of Costs portion of Volume II B. That study made several recommendations which have been incorporated in this calculation of marginal non-common costs. The one notable exception is that of the cost function called 'specific facilities'.

Low-voltage lines that serve only one municipality are now regarded as a specific facility and charged on the basis of capital cost. The study of fully distributed non-common costs recommends extending this concept to apply to all customer classes and also to the transformation function. Since line milage was a factor in determining the marginal costs of the distribution function, the specific-facility lines have, in effect, been included. (Although the use of line milage as a factor is contrary to the recommendations of the study of non-common costs, from the point of view of marginal costing, it is the correct approach.)

Time considerations prevented including specific transformer stations in the calculation of marginal cost for the transformation function. Class costs would only be affected if the load factors of specific stations varied substantially from non-specific stations. It was considered that the results obtained were sufficient for their primary use, which was to assist in setting rural rates.

III. TRANSFORMATION

The costs of transformation consist of the costs incurred by transformer and distributing-stations employed to step bulk power down to voltage levels below 115 kilovolts. Transformation costs were pooled into two groups:

1. transformation below 115 kV, but above 20 kV; and
2. transformation to below 20 kV.

The historical dividing-point of 10 kV was not used because the marginal-cost analysis indicated that 20 kV would produce a more homogeneous pooling of costs.

A. CAPITAL

The base data used in this calculation were taken from the transformation part of the study of non-common costs. In that study, marginal transformation costs were used to determine cost groupings for the various stages of transformation.

Capital costs of all of Ontario Hydro's distributing-stations as well as those of transformer stations placed in service in the last fifteen years were gathered. The costs of these stations were converted to 1974 dollars, and a cost per kVA of capacity by voltage level was calculated.

To translate these results into a marginal cost per kilowatt, an adjusting-factor was determined by expressing the actual loads for 1974 as percentages of the kVA capacity. The resulting factor, when applied to the original results, converted the unit cost from an incremental measure of capacity in dollars per kVA to an incremental $/kW term.

B. OPERATION AND MAINTENANCE

Operating and maintenance costs are recorded in accounts that designate the type of transformer station: that is, 230 kV, 115 kV or low voltage. As in the analysis of capital, the results of the transformation part of the study of non-common costs were used in the analysis of marginal O & M costs. The total operating and maintenance costs plus associated overheads, by type of station, were divided by the primary capacities of the stations, to obtain a cost of capacity (kVA). The obtained costs per kVA were weighted by the percentage of capacity composing each secondary level of transformation. For example, if 80 per cent of 44 kilovolts were transformed down from 230 kilovolts, and 20 per cent from 115-kilovolt, the 44-kilovolt cost would equal the sum of 80 per cent of the 230-kilovolt cost per kVA and 20 per cent of the 115-kilovolt cost per kilovolt-ampere. This procedure produced an operating and maintenance cost per kilovolt-ampere for each level of transformation, which in this analysis was translated to a cost per kilowatt in the same manner as capital.

C. TRANSFORMATION LOSSES

Stations that transform power from one voltage to a lower voltage are placed in two classifications, transformer stations and distributing-stations.

Transformer stations have a primary voltage (high side) of 115 kilovolts or higher. Distributing-stations have a primary voltage of less than 115 kilovolts. The costs associated with losses were calculated for each class.

For transformer stations, actual 1974 losses per transformer, for both demand and energy, were supplied by the System Maintenance Division.

For distributing-stations, it was estimated that losses from the transformer core would equal two per cent of capacity, and losses from the copper windings would be four per cent of capacity. (These percentages were derived from industry standards. It was considered that the volume of data requiring analysis, combined with the variation in load factors for distributing-stations, did not warrant calculating actual losses.) Using these loss estimates, losses for demand and energy were calculated. For demand, the two per cent was applied to ninety-five per cent of the 1974 rated capacity of distributing-stations. Energy losses were computed by applying the four per cent to the capacity determined above at eighty per cent load factor.

The loss data so obtained were related to the actual 1974 loads for transformer stations and to estimated loads (ninety-five per cent of rated capacity) for distributing-stations. In this way, average loss figures for demand (in watts per kilowatt) and energy (in kilowatt-hours per kilowatt per year) were obtained for each secondary voltage level.

The costs associated with these losses were calculated by applying the marginal demand and energy costs from the NERA study of bulk-power costs. It was necessary to weight the energy costs determined by period in the NERA study to determine an overall cost of energy. This was achieved by applying the proportion of hours in each period (winter, summer, off peak) to produce a weighted average energy cost.

IV. DISTRIBUTION

The costs of distribution are those of the low-voltage lines (primarily 44, 27.6 and 22 kilovolts) which distribute power from the transmission grid to the customers' supply points. There are significant differences in the average length of line required to serve each class of customer, and this is recognized in the current cost-of-power system. The low-voltage lines are included in the radial cost function, which is applied to classes on the basis of kilowatt-miles.

In determining marginal costs, it was decided that the milage factor deserved consideration. The rural customers could not be lumped with municipalities for costing-purposes, because of differences in line milage. Accordingly, costs were determined for each class of customer.

A. CAPITAL

The period used to determine the marginal cost of capital ran from 1971 to 1975. Because only net additions to load were available, it was necessary to use net additions to capital. New lines added to capital were converted to 1975 dollars using the specific factors appropriate to the year when each line was placed in service. The value of lines removed from capital because of sale, retirement, or transfer was converted at an average rate derived from data in the inflation-accounting study (Volume III).

The milage used in the current allocation process was adjusted to eliminate the milage of related lines of 115 kilovolts or more. The increase in the number of miles by class was calculated, and used as the basis for allocating the escalated capital to class.

These costs were then divided by the planned increases in low-voltage load for the period, to obtain a marginal cost of capital per kilowatt. (The planned load was used because this is the basis for decisions to alter present distributing-facilities.)

B. OPERATION AND MAINTENANCE

There are no operating-costs for low-voltage lines, only maintenance and associated overheads. These costs for 1975 were related to the total length of low-voltage line used in the present allocation process, and a cost per mile determined. The length in miles added by class from 1971 to 1975 was multiplied by the cost per mile, and the resulting product divided by the increase in low-voltage load planned for the same period to obtain a cost per kilowatt.

V. METERS

Metering is required for billing-purposes, and is mainly carried out below the 115-kilovolt level. For this reason, its cost is classified as non-common.

A. CAPITAL

The additions to meter capital for 1973 through 1975 were calculated in 1975 dollars. The increased costing-load related to meters for the same period, and an incremental capital cost per incremental kilowatt, were obtained.

B. OPERATION AND MAINTENANCE

A series of calculations produced the meter, operating, and maintenance costs plus associated overheads.

The share of total OM&A outlays related to capital added in 1974 was estimated. The following steps were taken in the analysis to produce this estimate:

1. The reproduction cost, in 1974 dollars, for meter capital as of 31 December 1974 was determined. (The source of this information was the inflation-accounting study and information from the cost-of-power system.)
2. The total OM&A expenses for meters were then related to the results of step (1), to determine an OM&A cost per dollar of capital investment.
3. The unit OM&A cost determined in step (2) was then applied to the 1974 additions to meter capital and the incremental OM&A costs were calculated by applying changes in the 1974 costing-load.

VI. Annualization and Escalation of Incremental Costs

All the incremental costs per kilowatt have been annualized at 10.5 per cent over 35 years in determining yearly incremental costs.

The costs were determined in 1974 or 1975 dollars, depending on available data, and converted to 1977, 1978, and 1979 dollars for use in designing rates. Indices provided by the Office of the Chief Economist were used to convert these figures.

The results of the analyses undertaken in this study are summarized in Appendix I.

PART 3: Marginal Costs For The Rural Retail System

I. INTRODUCTION

The object of this analysis is to determine the marginal costs of the rural retail system.

Providing electrical service to a retail customer, at a voltage below sub-transmission levels, requires designing and constructing a distribution network. This incurs capital, operating, maintenance, and administrative costs.

The accounting-system, in grouping and recording these costs, makes it possible to identify spending related to the chief components of the retail distribution system, on both an annual and a cumulative basis for capital, and annually for operating-expenses. To determine the marginal cost of providing service in the rural retail system, outlays made in 1975 have been analysed, and related to the changes in load, energy, and number of customers in that year.

II. CONCEPTUAL BASIS FOR ALLOCATING COSTS

Costs can be identified as variable or fixed depending on whether or not they change in relation to demand. Fixed costs include avoidable customer costs, incurred simply because a customer is connected to the system, as well as non-demand-related costs, which neither relate directly to a customer, nor vary with an increase or decrease in demand. Costs which do vary with demand are called demand-related costs: that is, they vary according to the number of kilowatts or kilowatt-hours the customer uses.

There are, however, costs which are both fixed and variable. There are also costs recorded in the capital accounts of the retail system which, for purposes of this exercise, are neither, such as those for water heaters and sentinel lighting.

III. ALLOCATING CAPITAL COSTS

First, those costs which were either wholly fixed or wholly variable were placed in their respective categories; these included the costs for such items as poles and switches. Other costs, although considered assignable (in part at least) to the demand, non-demand, and customer components, were allocated to either the fixed or the variable class. This was necessary because either not enough information was available to split costs, or only small amounts of money were involved. The allocating of meter costs to the fixed class serves as an example of this procedure.

The splitting of fixed and variable costs was carried out for conductors and transformers. The method used was that of the minimum intercept, which employs regression analysis.

The minimum-intercept method involves an interpretation of the Line of Best Fit determined in the regression analysis. Based on the assumption that there may be a non-demand component in even the smallest available unit size, the minimum-intercept method seeks to identify the share of plant related to a hypothetical no-load situation. The Line of Best Fit is extended to a no-load intercept, and the cost related to this load is the fixed component of the asset class.

Costs of installing transformers were also split into fixed and variable parts. The methodology in this case was based on the view that the cost of installing the smallest transformer is customer-related.

IV. ESTABLISHING THE UNIT COSTS FOR CONDUCTORS AND TRANSFORMERS

The unit-cost data were acquired from stores inventory records maintained within the Supply Division. These records list the amounts of each item used during the year, as well as the average cost of the items in inventory on 31 December 1975. (The data are kept by the code numbers identified in the Standard Stores Catalogue.)

Conductors were grouped in these six classes:

1. Aluminum - bare,
2. Steel Re-inforced - bare,
3. Copper - bare,
4. Aluminum - weather-covered,
5. Steel Re-inforced - weather-covered, and
6. Copper - weather-covered.

Using those sizes of conductor designated by Distribution Planning as used mostly in the retail system, a weighted average cost was computed for each size in each category, in dollars per foot. These weighted average costs were used in the regression analysis.

Transformers were grouped in these six classes:

1. pad-mounted, outdoor, single-phase;
2. pad-mounted, outdoor, three-phase;
3. pole-mounted, single-phase;
4. indoor, dry type;
5. submersible;
6. outdoor, surface-mounted.

A weighted average cost was computed for each size (kVA capacity) within each class, and these were then used in the regression analysis.

V. FIXED AND VARIABLE COMPONENTS OF CONDUCTOR EXPENDITURES

The load-carrying capacity of a given size of conductor varies according to the voltage level at which it is used.

The analysis of conductors required determining the load-carrying capacity of the various sizes for each voltage level of the retail distribution system. According to Distribution Planning, these were 25 kV, 13.8 kV, 12.5 kV, 8.32 kV and 4.16 kV.

The load-carrying capacity of each conductor size was established using the formula kW=(kV/1; 3)xI where kW = kilowatts per conductor, kV = kilovolts (phase to phase), and I = ampacity. Distribution Planning provided ampacities for bare conductors, by type and size, at a variety of ambient temperatures. The ampacity at 10 degrees celsius was used in calculating load-carrying capacity. For weather-covered conductors, the ampacities were reduced by 10 per cent to find their approximate load-carrying capacity.

The load data analysed can be seen in the accompanying 24-x-5 matrix. Each of these 120 variables has its own cost characteristics, therefore, the conductor analysis involves 240 variables.

A problem was posed by the need to group these variables together to express the cost of conductors as two variables: the minimum intercept or fixed cost, and the slope or variable cost.

Least-square analyses were used to combine the variables in the following four steps:

1. The Line of Best Fit was determined for each category of conductor at each voltage level, and the slope and Y-intercept were recorded.
2. Usage weightings were computed for each category of conductor, using the amounts of conductor ordered through Central Stores during 1975 as measures of use.
3. The classes of conductor were grouped under each voltage level by employing the results of step 1. This was done by determining the cost-per-foot variables in each category at various assumed load-carrying capacities, applying the usage weightings determined in Step 2, and combining the results at each kilowatt level. This process yielded a weighted average cost for each level of load, by voltage level.
4. A regression analysis was performed on the results of step 3, yielding a slope and intercept for each voltage level.

The intercepts determined in Step 4 are the minimum intercepts at each voltage level. As mentioned, a variety of voltage levels are used in the retail distribution system. An analysis of the length of line added to the retail system in 1975 made it possible

Load Carrying Capacity by Voltage Level

		25 kV		13.8 kV		12.5 kV		8.32 kV		4.16 kV	
		$/ft.	kW	$/ft.	kW	$/ft.	kW	$/ft.	kW	$/ft.	kW
	Aluminum - Bare										
1.	Sizes: 4/0	.116	7072.5	.	3940.0	.	3536.2	.	2353.7	.	1176.8
2.	336.4	.184	9511.8	.	5250.5	.	4755.9	.	3165.5	.	1582.7
3.	556.5	.320	.	.	.	.	.	.	.	.	.
	Steel Reinforced - Bare										
4.	Sizes: 2	.051	.	.	.	.	.	.	.	.	.
5.	1/0	.077	.	.	.	.	.	.	.	.	.
6.	3/0	.135	.	.	.	.	.	.	.	.	.
7.	4/0	.139	.	.	.	.	.	.	.	.	.
8.	336.4	.203	.	.	.	.	.	.	.	.	.
9.	477.0	.281	.	.	.	.	.	.	.	.	.
10.	605.0	.412	.	.	.	.	.	.	.	.	.
11.	795.0	.575	.	.	.	.	.	.	.	.	.
12.	1192.5	.807	.	.	.	.	.	.	.	.	.
	Copper - Bare										
.	.		.	.	.	.	.	.	.	.	.
.	.		.	.	.	.	.	.	.	.	.
.	.		.	.	.	.	.	.	.	.	.
	Copper - Weathercovered										
21.	Sizes: 2	.299	.	.	.	.	.	.	.	.	.
22.	1/0	.425	.	.	.	.	.	.	.	.	.
23.	2/0	.539	.	.	.	.	.	.	.	.	.
24.	4/0	.924	7950.0	.	4388.4	.	3975.0	.	2645.7	.	1322.8

to extend the dollar value of these intercepts (cost per foot) into the fixed share of conductor costs.

In order to use the figures for length of line as above, the amount added at each voltage level was needed. This was estimated using voltage data (from the Load Service Questionnaire) pertaining to the various areas in the rural system. The length of line, converted to feet, was quadrupled to reflect the four-wire system. The number of feet at each voltage level was then multiplied by the respective minimum intercepts (cost per foot) to determine the total fixed, or non-demand-related, cost of conductor.

Voltage Level	Number of Feet of Conductor Added	Minimum Intercept Cost per Foot	Total Fixed Cost
12.5 kV	7,389,465.6	.04508	$333,117
8.32 kV	7,280,275.2	.04599	334,820
4.16 kV	154,598.4	.04956	7,662
			$675,599

Once the non-demand-related cost is determined, the demand-related cost is the remainder spent during the year on conductors, that is, $15,047,505.

VI. FIXED AND VARIABLE COMPONENTS OF TRANSFORMER EXPENDITURE

The analysis of transformers was much simpler than that of conductors, in that a measure of load carrying capacity is given in their ratings (kVA). The collected data was analysed, using the regression technique, in two groupings, as follows:

1. Single-phase transformers with a rated capacity of no more than 50 kVA (the method proposed by the NARUC cost-allocation manual);
2. transformers of all sizes.

In each methodology, the data were analysed by transformer category, with each category yielding a minimum intercept value. Weightings were then computed for each category of transformer, using the amounts ordered through Central Stores in 1975. These were applied to determine a weighted average intercept value. The analysis of group-1 transformers produced a weighted average intercept of $148.06. This analysis of all data produced a value of $194.45.

The next step was to determine the fixed share of 1975 capital expenditures for transformers. This required determining the number of transformers added to capital during the year. This information, however, was not available from the accounting-records. Neither were the data provided through the Central Stores records usable as a measure. (The reasons for this were first that each area office maintains its own inventory, and secondly that some purchases may be of a special nature. Therefore, not all transactions will necessarily be accounted for in stores records.)

Instead, the measure of the number of transformers used during the year was obtained from the Transformer Update Report prepared with data from the area offices. The report contains the number of transformers added, removed, and replaced each month. (The figure used in the analysis was the net quantity after additions and removals.)

The total fixed or non-demand-related costs for the year were then determined by multiplying the net number of transformers added by the minimum intercept value.

Net number of transformers installed in 1975	32,989
Weighted average minimum intercept	$148.06
Total fixed cost	$4,884,351.00

Once the non-demand-related cost was determined, the demand-related cost was the remainder spent on transformers during the year: that is, $5,674,290.

VII. FIXED AND VARIABLE COSTS OF INSTALLING TRANSFORMERS

As was already mentioned, the fixed costs of installing transformers are considered to be the cost of installing the smallest transformer.

To calculate this, the man-hours and labour costs per hour required to install the smallest transformer were determined. These data yielded a cost of $105.37 for installing each transformer. This amount, when multiplied by the total number of transformers installed during the year, yielded the fixed or non-demand-related costs of installing transformers.

Net number of transformers installed in 1975	32,898
Cost of installing each transformer	$105.37
Total fixed cost	$3,476,050.00

Once the non-demand-related cost of installing transformers was determined, the demand-related cost was the remainder spent during the year: that is, $1,090,584.

VIII. RESULTS OF CAPITAL ALLOCATION

After having been allocated as above, the different costs were totalled as follows:

Variable or demand-related portion	$25,668,919
Fixed or non-demand-related portion	$32,691,177
Unallocated costs	$3,627,622

IX. ALLOCATING COSTS FOR OPERATION, MAINTENANCE, AND ADMINISTRATION

There are operation, maintenance, and administrative expenses related to capital outlays in 1975 that should be considered in determining the marginal costs of the retail system. A series of calculations determined these and allocated them to the fixed and variable classes.

The part of total OM&A expenditures in 1975 related to capital added during that year was estimated using the following steps:

1. The reproduction cost of the Retail Distribution Plant shown on the Statement of Financial Position as of 31 December 1974 was determined in 1974 dollars. (The source of the data was an inflation-accounting study undertaken within Ontario Hydro.)
2. The historical costs of retirements made in 1975, adjusted to 1974 dollars, were deducted from the results of step 1.
3. The results of step 2 were converted to 1975 dollars.
4. The capital additions to the retail system in 1975 (adjusted to reflect the lag in construction and in-service dates) were added to the results of step 3, yielding an approximation of retail-plant capital as of December 31, 1975, in 1975 dollars. This value was $1,271,567.
5. The total OM&A expenses of the retail system were then related to the results of step 4 to determine an OM&A cost per dollar of capital investment. The result of this calculation was $.0444.
6. The unit OM&A cost determined in step 5 was then applied to the fixed and variable portions of the capital additions to rural plant in 1975. The results of these applications were non-demand-related and demand-related OM&A costs, as follows:

	1975 Capital Additions	OM&A Unit Cost	Marginal OM&A Expenses
Fixed or Non-Demand Related	$32,691,177	$.0444/$capital	$1,451,488
Variable or Demand-Related	$25,668,919	$.0444/$capital	$1,139,700

X. DETERMINING INCREMENTAL FIXED AND VARIABLE COSTS

As was already mentioned, providing electricity to a retail customer incurs capital, operating, maintenance, and administrative costs. The fixed and variable costs for 1975 have been allocated between fixed and variable as follows:

	Fixed Costs	Variable Costs
Capital	$32,691,177	$25,668,919
O M & A	$1,451,488	$1,139,700

The marginal costs of the rural retail system have been determined in this study, by relating them to changes in load, energy, and the number of customers during 1975.

Peak demand in the rural system served as the measure of load. However, owing to the mild winter of 1974 and the resulting low-load conditions, the change in the peak between 1974 and 1975 was considered abnormal. An estimate was therefore made of what the normal growth in peak load would have been, by applying the average rate of growth from 1971 to 1975. This rate of 11.73 per cent, when applied to the 1975 peak of 2,962,658 kW, yielded a growth of 252,571 kilowatts.

The difference between the total energy consumed in the rural system in 1974 and 1975 revealed an energy growth of 533,437,023 kilowatt-hours.

The number of customers used to determine the marginal customer cost was 34,906, the number added in 1975.

When applied to the fixed and variable costs, these measures yielded the incremental costs in the rural retail system. The results are summarized in Appendix III.

XI. ANNUALIZING AND ESCALATING INCREMENTAL COSTS

The incremental costs related to capital have been annualized at 10.5 per cent over 35 years to determine yearly incremental costs. Since annual incremental costs were already calculated for OM&A, no annualizing adjustment was required.

The incremental costs of capital and OM&A in 1975 dollars were converted to 1977, 1978, and 1979 dollars for use in designing rural retail rates. Indices provided by the Office of the Chief Economist were used to escalate the amounts.

The results of the analyses undertaken in this study are summarized in Appendix IV.

SUMMARY OF MARGINAL NON-COMMON COSTS IN 1977, 1978, AND 1979 DOLLARS

	$/kW		
	1977	1978	1979
Transformation (Notes 1 & 3)			
I Less than 115 kV but more than 20 kV	8.32	9.05	10.05
II Less than 20 kV	12.21	13.42	14.90
Distribution (Notes 2 & 3)			
Rural	6.33	6.92	7.67
Meters (Note 4)	.24	.26	.28

Notes

1. The rate for a customer taking power at less than 20 kV is as shown. It is not the total of the two transformation rates as in the present system.

2. These figures were based on revised costing-loads that reflect the transfer of municipal customers' loads over 5000 kW to the direct class. Data from 3000 kW to 5000 kW were not available. These rates do not include the cost of line losses.

3. These costs are calculated on costing-loads applicable to the function. The following percentages of total loads forecast the period 1977 to 1979 for the rural class.

Transformation I	97.7	
Transformation II	82.0	(based on 1974 actual)
Distribution	97.7	

4. This rate is for total load, not just Stage - 1 transformation loads as at present.

NEW INFORMATION REQUIREMENTS FOR ELECTRICITY COSTING MARGINAL NON-COMMON FUNCTION COSTS

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
1.	Historical costs per year of transformer and distributing stations built for the past 15 years	Base for capital component. Includes large enough sample to produce reasonable confidence limits without including old atypical stations	Plant Accounting	Past 15 years computerized, requires annual updating
2.	Primary and secondary voltages and firm ratings of all transformer stations, and nameplate ratings of all distributing-stations	Used as basis for establishing station capacity	Stations T & D	Past data computerized, requires annual updating
3.	Peak annual demands of each transformer and distributing-station	Calculation of transformation costs and losses	Statistics from Power System Operations	
4.	Costing-load by voltage	Calculation of transformation losses	Computing Services	Program available
5.	Copper and core losses of transformer stations	Calculation of transformation losses	Electrical Maintenance of System Maintenance	Available but not readily

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
6.	Marginal cost of demand and energy	Calculation of transformation losses	Power Costing	Expected to be produced annually
7.	Miles of low voltage line by class of customer	To allocate marginal distribution costs to classes	Stations T & D	Not available
8.	Load forecast broken into bulk power and distribution voltages	To assist in allocation of marginal distribution costs to classes	Power Market Analysis	Not available
9.	Low voltage costing load taken over radial lines	To permit allocation of marginal distribution costs to classes	Input by regions to Load Service Questionnaire	Not available except through manual estimates
10.	Economic Forecasting Series	Conversion of costs to current dollars	Office of the Chief Economist	Produced periodically

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
11.	Electric Utility Construction Price Index for transformer stations	To convert capital cost of stations to current dollar	Office of the Chief Economist	Produced annually by Statistics Canada
12.	Estimate of percentage of labour and material composing capital cost of low voltage lines and stations built for past 5 years	To permit application of escalation factors	Stations T & D	Not presently calculated
13.	Estimate of percentage of labour and material composing stations and low voltage lines operating and maintenance costs	To permit application of escalation factors	System Maintenance	Not presently calculated Direct labour available from Integrated Information System

SUMMARY OF INCREMENTAL FIXED and VARIABLE COSTS FOR 1975 IN THE RURAL RETAIL SYSTEM IN 1975 DOLLARS

CAPITAL

Number of customers added in 1975	34,906
Fixed Costs	$32,691,177
Cost per customer added	936.55
Annualized @ 10.5% over 35 years	101.44
Amount of energy in rural system 1974	11,575,515,362
Amount of energy in rural system 1975	12,108,952,385
Difference	533,437,023
Variable costs	$25,668,919
Cost per incremental kWh	.04812
Annualized @ 10.5% over 35 years (per kWh)	.00521
Load growth 1975 (December estimate)(kW)	252,571
Variable costs	$25,668,919
Cost per incremental kW	101.63
Annualized @ 10.5% over 35 years (per kW)	11.01

OM&A

Number of customers added in 1975	34,906
Fixed costs	$1,451,488
Cost per customer added	$41.58
Amount of energy in rural system 1974	11,575,515,362
Amount of energy in rural system 1975	12,108,952,385
Difference	533,437,023
Variable costs	$1,139,700
Cost per incremental kWh	.00214
Load growth 1975 (December estimate)(kW)	252,571
Variable costs	$1,139,700
Cost per incremental kW	4.51

SUMMARY OF INCREMENTAL FIXED and VARIABLE COSTS IN THE RURAL RETAIL SYSTEM IN 1975, 1977, 1978, and 1979 DOLLARS

Capital	1975 $'s	1977 $'s	1978 $'s	1979 $'s
Annualized cost per customer added	$101.44	$123.76	$134.71	$149.73
Annualized cost per incremental kWh	$.00521	$.00636	$.00692	$.00769
Annualized cost per incremental kW	$ 11.01	$ 13.43	$ 14.62	$ 16.25
OM&A				
Annualized cost per customer added	$ 41.58	$ 49.69	$ 54.01	$ 59.75
Annualized cost per incremental kWh	$.00214	$.00256	$.00278	$.00308
Annualized cost per incremental kW	$ 4.51	$ 5.39	$ 5.68	$ 6.48

INFORMATION REQUIREMENTS FOR ELECTRICITY COSTING:

MARGINAL COSTS IN THE RETAIL SYSTEM (Historical Costs of the Latest Year)

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
1.	Additions to rural capital by plant sub-account (i.e., transformers, conductors, etc.)	To identify expenditures made during the year for retail plant	Plant and Depreciation Accounting	Available
2.	Average unit cost of conductors and transformers by size of item	To use in regression analysis to determine fixed and variable conductor and transformer expenditures	Supply Division Materials Systems	Sources exist on computer file but a program-change is required to provide data as required
3.	Load-carrying capacity of various conductor sizes used in the retail system by voltage level	To use in regression analyses to determine fixed-variable portions of conductor expenditures	Distribution Planning	Source data exist but further computations are required
4.	Number of transformers added to the retail system during the year	To determine the customer-related portion of transformer expenditures	Computing Services Division	Changes in the number of transformers are recorded but a change is required to provide data as required

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
5.	Number of customers added to the Retail System during the year	To determine unit customer-related costs	Power Market Analysis	Available
6.	Changes in peak loads during the year	To determine unit demand-related costs	Financial and Operations Accounting	Available
7.	Installation cost for smallest transformers	To determine customer-related costs of Installing transformers	Regions	Source data exists but further computations are required
8.	Miles of low voltage line added by voltage level	To determine customer-related conductor expenditures	Unknown	Data is available by area, but voltage levels are not indicated
9.	Operation, maintenance and Administration costs for the year for the retail system	To determine incremental OM&A	Financial and Operations Accounting	Available

	Information Required	Reason for Requirement	Expected Information Source	Current Availability of Information
10.	Estimate of the replacement cost of retail plant in the Statement of Financial Position	To determine incremental OM&A	Unknown	Data was provided in the Inflation Accounting Study
11.	Changes in energy during the year	To determine unit demand-related costs	Financial and Operations Accounting	Available
12.	Number of transformers and feet of line issued by Central Stores during the year	To use in analysis to determine fixed and variable transformer and conductor expenditures	Supply Division Materials Systems	Sources exist on computer file but a program change is required to provide data as required
13.	Cost of poles added during the year (excluding replacements and retirements)	To determine customer-related pole costs	Unknown	The data available is on a net basis (estimates have to be made for replacements and retirements)